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BEFORE THE ARIZONA CORPORATION COMMISSION

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WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
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Commissioner

IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	E-00000A-02-0051 E-01345A-01-0822 E-00000A-01-0630 E-01933A-02-0069 E-01933A-98-0471 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

Staff hereby provides notice of filing its Direct Testimony in this docket. An original and ten copies are submitted of the Prefiled Direct Testimony of Barbara Keene, Matthew Rowell, Jerry Smith, Neil Talbot and David Schlissel (redacted version). Copies of the unredacted version of Mr. Schlissel's Testimony are being provided to parties who have executed an appropriate Protective Agreement.

RESPECTFULLY SUBMITTED this 29th day of March, 2002.

Christopher C. Kempley

Christopher C. Kempley, Chief Counsel
Janet Wagner, Attorney
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007
(602) 542-3402

Original and ten copies of the foregoing filed this 29th day of March, 2002, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Arizona Corporation Commission
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MAR 29 2002
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Copy of the foregoing mailed and electronically provided this 29th day of March, 2002, to:

All parties of record

Nancy Roe

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DIRECT

TESTIMONY

OF

MATTHEW ROWELL
BARBARA KEENE
JERRY SMITH

DOCKET NO. E-01345A-01-0822

MARCH 29, 2002

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
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IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	))))	DOCKET NO. E-01345A-01-0822

DIRECT

TESTIMONY

OF

MATTHEW ROWELL

TELECOMMUNICATIONS AND ENERGY SECTION CHIEF

UTILITIES DIVISION

MARCH 29, 2002

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TABLE OF CONTENTS

Page

INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Matthew Rowell. My business address is Arizona Corporation Commission, 1200 West Washington Street, Phoenix, Arizona 85007.

Q. What is your position at the Commission?

A. I am the Chief of the Telecommunications and Energy section of the Commission's Utilities Division.

Q. Please describe your education and professional background.

A. I received a B.S. degree in economics from Florida State University in 1992. I spent the following four years doing graduate work at Arizona State University where I received a M.S. degree and successfully completed all course work and exams necessary for a Ph.D. My specialized fields of study were Industrial Organization and Statistics. I was hired by the Commission in October of 1996 as an Economist II. Prior to my Commission employment I was employed as a lecturer in economics at Arizona State University, as a statistical analyst for Hughes Technical Services, and as a research analyst at the Arizona Department of Transportation.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarily describe Staff's recommendations regarding Arizona Public Service Company's ("APS") request for a variance from compliance with Arizona Administrative Code ("A.A.C.") R14-2-1606(B) and APS' request that the Arizona Corporation Commission ("Commission") approve a long-term purchase power agreement ("PPA") between APS and its parent corporation, Pinnacle West Capital Corporation ("PWCC"). (APS' request for a variance and for approval of its proposed PPA will be collectively referred to as "APS' request.") I also will introduce the testimonies of other Staff witnesses.

Q. Can you briefly describe the other testimonies on which Staff's recommendations are based?

A. Staff's recommendations are based on the findings set forth in the testimonies of Staff witnesses Barbara Keene and Jerry Smith and in the testimonies of Staff's consultants David Schlissel and Neil Talbot. Ms. Keene's testimony explains issues regarding competitive bidding as it relates to the wholesale marketplace. Mr. Smith's testimony documents the status of existing and emerging electric system infrastructure in Arizona with an emphasis on the short-term and long-term practicality of competitively bidding 50 percent of Standard Offer retail customer load per A.A.C. R14-2-1606. Mr. Schlissel's testimony addresses the appropriateness of APS' proposed PPA. Mr. Talbot's testimony addresses the wholesale competition and electric restructuring experiences of other states around the country.

STAFF'S RECOMMENDATIONS

Q. Can you briefly summarize Staff's recommendations?

A. Yes. Staff recommends the following:

1. Staff recommends that the proposed purchase power agreement not be approved. David Schlissel submitted testimony on behalf of Staff that describes in detail the deficiencies of that proposed agreement. As a result of Mr. Schlissel's detailed analysis of APS' proposed agreement, Staff does not believe that approving the agreement would be in the public interest and would hinder the development of a competitive market.

2. Staff recommends that APS be temporarily relieved from the obligation of purchasing 100 percent of the generation needed to serve standard offer customers from the competitive market. However, Staff does not recommend approval of the full variance to R14-2-1606(B) that APS has requested. In place of APS' variance request, Staff recommends that APS be granted a variance with the following characteristics:

a.) The variance will be temporary. It will apply only while the generic review of electric restructuring (E-0000A-02-0051) is in process. Staff expects that a permanent resolution of how competitive bidding will proceed will be developed in the generic docket.

b.) If the generic review of electric restructuring is not completed by January 1, 2003, APS will be required to use a competitive bidding process to procure generation to serve standard offer load under the following circumstances.

i) To serve all load growth (defined below.)
ii) To serve all load outside of the transmission constrained areas defined in Mr. Smith's testimony.
iii) Whenever APS seeks to purchase power from any of its affiliates it will do so through a competitive bidding process.
iv) APS will use a competitive bidding process to acquire generation that equals any new Available Transmission Capacity ("ATC") to the transmission constrained areas.

c.) APS will be required to submit a plan to Staff within 30 days of a Commission decision on APS' request for a variance. The plan should address how APS intends to implement a bidding process for the generation described in b) above. The plan should describe the process in detail and include evaluation criteria.

3. Staff recommends that the transfer and separation of APS' generation assets as identified in Rule R14-2-1615(A) be stayed pending completion of the Commission's generic review of electric restructuring under Docket No. E-0000A-02-0051. This recommendation extends the two-year delay built into the APS Settlement agreement and is justified given the current status of the competitive market in Arizona.

Q. Can you expand on Staff's recommendation number 1, that APS' proposed Purchase Power Agreement not be approved.

A. Yes. David Schlissel's testimony detailed several problems with the proposed PPA. As a result of Mr. Schlissel's findings, Staff concluded that approval of the PPA is not in the public interest. Therefore, Staff recommends that the Commission not approve APS' proposed PPA.

Staff's recommendation concerning the PPA is independent of our recommendation regarding APS' variance request. Staff believes that given the flaws identified in the proposed PPA, the proposed PPA should not be approved regardless of how the Commission ultimately rules upon APS' request for a variance from the competitive bidding requirements of R14-2-1606(B).

Q. Can you expand on Staff's recommendation number 2 (a), that Staff's proposed alternative variance be temporary and be replaced with a permanent process at the conclusion of the generic docket?

A. Yes. For reasons discussed below, Staff believes that some form of a variance from R14-2-1606(B) is appropriate at this time. However, APS' proposal goes further than is necessary. APS' proposal eliminates the 50 percent bidding requirement and replaces it with the PPA which is not in the public interest. Staff seeks to maintain the balance struck by the rules in 1999. In Staff's opinion the rules sought to create an environment in which competition might develop while at the same time providing reasonable protection to Arizona's consumers from the risks associated with a competitive marketplace. Nonetheless, Staff believes that a temporary variance coupled with a review of the relevant issues is far superior to the option of a 28-year contract with terms that are not in the public interest. Thus, Staff believes that the issues regarding competitive bidding should be investigated in detail through the generic docket.

Q. Can you expand on Staff's recommendation number 3 (b), that APS be required to implement a competitive bidding process if the generic review of restructuring is not completed by January 1, 2003?

A. Yes. The testimony of Staff witness Jerry Smith describes the transmission constraints on APS' system. As Mr. Smith explains in his testimony, Staff believes that because of these constraints it is not practical for APS to comply with the full requirements of R14-2-1606(B). However, Staff does not believe that a complete exemption from that rule is necessary or prudent at this time. Staff believes that its recommendation recognizes current realities and strikes the appropriate balance between what is practical and the pro-competitive intent of R14-2-1606(B). Staff's recommendation should act as a starting point or "straw man" for discussions in the generic docket. If the competitive bidding issue is not resolved in the generic docket by January 1, 2003, APS should be required to implement Staff's recommendation. Staff believes its recommendation is practical and that it will have a positive effect on competition in Arizona.

Each of the requirements of Staff's recommendation three b.) are discussed in more detail below. Staff realizes that these requirements are not necessarily mutually exclusive, i.e., there may be some overlap in the categories of generation that Staff is recommending APS purchase through a competitive bidding process.

Q. Can you expand on the first requirement of Staff's recommendation 2 (b), that a competitive bidding process be used to procure all generation used to serve all load growth?

A. If the generic review of electric restructuring is not completed by January 1, 2003, Staff recommends that all generation needed to supply new load be purchased through a competitive bidding process. Staff defines new load as the year over year difference between forecasted summer peak loads. APS does not currently own the generation necessary for it to supply this load growth itself. Thus, this generation will need to be purchased regardless of the resolution of APS' variance request.

Q. Can you expand on the second requirement of Staff's recommendation 2 (b), that generation needed to serve all load outside of the transmission constrained areas be purchased through a competitive bidding process?

A. Yes. Mr. Smith's testimony indicates that there are significant load pockets in APS' service territory that face transmission import constraints (the Phoenix and Yuma areas.)

Because of these import constraints, implementing a competitive bidding process to procure generation to serve these load pockets would be problematic. However, for load located outside of these constraints, Staff does not know of any reasons why a competitive bidding process cannot work. Staff believes that there is an adequate amount of generation located around Arizona to make competitive bidding to serve this load feasible.

Q. Can you expand on the third requirement of Staff's recommendation 2 (b), that whenever APS seeks to purchase from any of its affiliates it does so through a competitive bidding process?

A. Yes. Staff believes that it would be appropriate to subject any proposed purchases by APS from its affiliates to a competitive bidding process. Such purchases should result from arms' length negotiations. Staff believes that subjecting the basic terms of any proposed purchase from an affiliate to a competitive bidding process will ensure that these purchases are negotiated in an arms' length manner. In addition, because it would allow merchant generators an opportunity to bid that may be foreclosed to them otherwise, subjecting proposed purchases from affiliates to a competitive bidding process will serve to enhance the development of a competitive wholesale power market for Arizona.

APS' affiliate PWEC currently owns a significant amount of generation assets. Thus, purchases by APS from its affiliates are possible even if the transfer of APS' generation assets is stayed pending completion of the generic docket.

Q. Can you expand on the fourth requirement of Staff's recommendation 2 (b), that APS will purchase through a competitive bidding process an amount equal to any new Available Transmission Capacity ("ATC") to the transmission constrained areas?

A. Yes. Mr. Smith's testimony indicates that there are significant load pockets in APS' service territory that face transmission import constraints (the Phoenix and Yuma areas.)

Because of these import constraints, implementing a competitive bidding process to procure generation to serve these load pockets would be problematic. However, over time these transmission constraints are likely to be mitigated. As new plants come on line within the constrained areas the ATC may increase. Also, transmission resources may be upgraded. As this happens, Staff believes that APS should be required to conduct a competitive bidding process to procure the generation that the new ATC would allow to be imported.

Some of APS' higher cost generating plants (in terms of operating costs) are located within the Phoenix transmission constraint. Thus, requiring competitive bidding within the transmission constrained areas as soon as it is feasible could allow for that more costly generation to be replaced with less costly generation.

Q. Are there any exceptions to the above competitive bidding requirements that Staff believes should be allowed?

A. Yes. APS may need to make emergency or short-term purchases for reliability or economic dispatch reasons. Such purchases should be exempt from the competitive bidding process. However, APS should not use these purchases to manipulate the bidding process. APS' plan for implementing the bidding process should include clear definitions of emergency or short-term purchases for reliability or economic dispatch reasons.

Q. Can you expand on Staff recommendation 2 (c), that APS be required to submit a plan within thirty days of a Commission Decision on its request for a variance that describes how the competitive bidding process will be conducted?

A. Yes. Staff recommends that APS be required to submit a plan for Staff review and Commission approval which details how APS intends to implement the above-described bidding process. Staff witness Barbara Keene has submitted testimony regarding competitive bidding processes. Ms. Keene's testimony indicates that a well-defined and transparent plan is an essential part of any competitive bidding process. The plan should be transparent and at a minimum the plan should contain the block size or sizes, price and non-price evaluation factors, the scoring system, pricing arrangements, bidder qualifications, performance provisions, and procedures for evaluating bids from APS affiliates. The plan should also include APS' definition of emergency or short-term purchases for reliability or economic dispatch reasons. The plan should also include an explanation of how APS will determine the amount of newly available ATC. APS should file its plan in this docket within thirty days of a Commission decision in this docket. Other parties in this docket should have fourteen days to comment on APS' plan.

Q. Can you expand on Staff's recommendation number 3, that the transfer and separation of APS' generation assets as identified in Rule R14-2-1615(A) be stayed pending completion of the commission's generic review of electric restructuring under docket no. E-0000A-02-0051?

A. Yes. On January 22, 2002 the generic docket was opened to address issues affecting the restructuring of the electric power industry in Arizona. Staff believes that the transfer and separation of generation assets is an issue, which needs to be reexamined in the generic docket. Generally, proponents of competition argue in favor of asset transfers and separation in order to eliminate the market power of incumbent utilities in the wholesale generation market. The elimination of the incumbent's market power was seen as a necessary precursor to the development of a truly competitive wholesale market. APS envisions a transfer of the bulk of APS' generation assets to its affiliate Pinnacle West Energy Corporation ("PWEC"). In Staff's opinion such a transfer will not result in a reduction in market power. It merely shifts market power from APS to its affiliate PWEC. Thus, any potential pro-competitive effects that the reduction in market power might be expected to engender are not likely to be realized. In fact, a transfer of generation assets from APS to its affiliate would transfer the market power from an entity that is regulated by the Commission to an entity that is largely outside of the Commission's jurisdiction.

In addition to not having any pro-competitive effects, it is my understanding that the transfer of assets from APS to its affiliate would have the effect of limiting the Commission's ability to determine the ratemaking treatment for those assets. If the transfer were to go forward, the sale of generation from PWCC (or PWEC) to APS would be a wholesale transaction over which the Commission lacks authority.

Thus, allowing the transfer of assets would result in a substantial decrease in the Commission's regulatory oversight of APS without a corresponding increase in the likelihood that competitive forces will serve to replace that regulatory oversight.

In the Generic Electric Restructuring Docket ("Staff Report"), Staff identified alternatives to the asset transfers contemplated by APS. Staff recommends that options such as requiring the transfer of assets to a functionally (but not legally) separate entity within the utility be considered in the generic docket. Transfer of assets to a functionally separate entity may allow for the same benefits as transfer to an affiliate without the corresponding loss of Commission jurisdiction. In such an environment the Commission would be in a position to address market power issues if they were to arise. An alternative (but not necessarily mutually exclusive) option is to allow or require the transfer of generation assets to non-affiliated companies in a much more gradual manner than envisioned by the existing rules. These and other options should be examined in depth during the course of the generic docket.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
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MARC SPITZER
Commissioner

IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	))))	DOCKET NO. E-01345A-01-0822

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

MARCH 29, 2002

TABLE OF CONTENTS

PAGE

APPENDIX

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst. My duties include evaluation of electric utility special contracts, review of utility tariff filings, assessment of utility demand-side management programs, and analysis of electric utility production costs and marginal costs. A copy of my résumé is provided in the Appendix.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01345A-01-0822?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony is concerned with competitive bidding. I will present recommendations regarding a competitive bidding plan for Arizona Public Service Company ("APS").

COMPETITIVE BIDDING PROCESS

Q. What is competitive bidding?

A. Competitive bidding is a process where participants submit bids to compete for the right to sell or to buy.[1]

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[1] Daniel J. Duann, Robert E. Burns, Douglas N. Jones, and Mark Eifert; *Competitive Bidding for Electric Generating Capacity: Application and Implementation*; The National Regulatory Research Institute; November 1988; p. 1.

Q. What requirement for competitive bidding is contained in the Retail Electric Competition Rules?

A. Arizona Administrative Code ("A.A.C.") R14-2-1606.B. requires investor-owned utilities to purchase power for Standard Offer service from the competitive market through prudent, arm's length transactions and with at least 50 percent through a competitive bid process.

Q. How do the Retail Electric Competition Rules define the competitive bid process?

A. The Retail Electric Competition Rules are silent on the process for competitive bidding.

Q. What are the implications of the rules being silent as to the process for bidding?

A. The lack of a specific process potentially allows utilities to develop their own processes for seeking and evaluating bids without any regulatory oversight.

Q. Is it in the public interest to allow utilities such as APS to exercise complete discretion in designing their own competitive bidding processes?

A. No. First, it is probable that affiliates of APS will want to bid to provide energy to serve a portion of APS' standard offer service load. Because APS' affiliates may be participating in the bidding process, APS will have an interest in the outcome. Regulatory oversight of the process is the only way to ensure that all parties will be treated fairly.

Second, this would be the first competitive bidding under the Retail Electric Competition Rules in Arizona. Bidders need to know the rules of the game and that they will be treated fairly. If everyone knows the rules, it may maximize participation and improve the quality of the bids. This can only benefit the public.

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Q. Why should a process be defined?

A. Some definition of the process is necessary to ensure that the benefits of competitive bidding are realized.

Q. What are the benefits of competitive bidding?

A. Some of the benefits of competitive bidding are improvement in economic efficiency and cost savings for ratepayers.[2]

Q. What are the pitfalls of competitive bidding?

A. Some possible pitfalls of competitive bidding include bid rigging, price fixing, market allocation schemes, and the "optimistic bidding strategy" where the bidder prices at a discount now and hopes to raise the price later.[3] A defined bidding procedure can help to avoid these pitfalls.

Q. How else can a defined bidding process or procedure be beneficial?

A. By having a defined process or procedure, potential bidders would have more information about how their bids would be evaluated and compared to others. Potential bidders may be more likely to bid.

Q. **What is a bidding procedure?**

A. A bidding procedure is a set of rules that specify: the conditions of participation, how winning bids will be selected, how the payment to the winning bidders will be determined, and definitions of other relevant bidding arrangements.[4]

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2 Duann, et al; p. 59.
3 Duann, et al; pp. 70, 75, and 76.
4 Duann, et al; pp. 78-79.

Q. What are the features of a competitive bidding process to obtain electric generation?

A. There is no typical way of soliciting bids, but the following steps are usually involved: specification of the supply block, preparation of a Request for Proposal ("RFP"), evaluation and selection of bids, and negotiation and contracting after bid selection.[5]

Q. What is the supply block?

A. The supply block is the amount of capacity, usually expressed in megawatts, that the utility wants to secure during the planning horizon to meet its projected demand and reliability requirements.[6]

Q. What is included in an RFP?

A. The RFP, which is publicized, includes the conditions of bidding, such as the supply block, ranking formula, pricing formula, and bidder qualification questionnaire.[7]

Q. What is involved in bid evaluation?

A. Bid evaluation is based on cost, reliability, dispatchability, transmission requirements, project risk, performance warranty, and any other factors peculiar to the utility.[8]

Q. What is included in the negotiation step of the process?

A. Negotiation is used to fine-tune the details of purchase arrangements and to reduce uncertainty and ambiguity (e.g. security provisions and penalties for unsatisfactory performance), but it should not alter the economic terms presented in the RFP.[9]

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5 Duann, et al; p. 8.
6 Duann, et al; p. 9.
7 Duann, et al; p.10.
8 Duann, et al; p.11.
9 Duann, et al; p.12.

OTHER STATES' EXPERIENCES

Q. Is there experience with competitive bidding for electric generation in other states?

A. Yes. Other state public utility commissions, starting with the Maine Public Utility Commission in 1984, have adopted various bidding programs.

Q. Please give an example of a bidding program.

A. Colorado established competitive bidding as part of its Integrated Resource Planning rules.[10] Bidding occurs every three years for ten-year contracts covering differences in load and resources, including forecasted load growth, existing contract expiration, and resource retirements. Within 30 days of a public participation process, the utility publishes an RFP. The RFP includes the bid evaluation criteria, including the weights to be assigned to each criterion that the utility plans to use in ranking the bids received. Specific information associated with the evaluation criteria includes: preferred fuel types, the extent to which resources must be located in certain geographic areas, transmission constraints and costs, dispatchability, resource reliability requirements, desirability of firm pricing and contract terms of various durations, any price cap or cash flow constraints, and any other important non-price factor. The RFP also includes the utility's standard contract for the acquisition of resources.

Thirty to 45 days after publication of the RFP, the utility convenes a bid conference open to all potential bidders. After the conference, the utility publishes the date for submission of sealed bids. Bids are submitted with an application fee of $1.00 per kW with a minimum fee of $1,000 and a maximum fee of $25,000. Bids must include: a firm price offer for capacity and energy, the anticipated availability factor, the period of time for which the quoted price is guaranteed, and the cost of any required transmission and distribution up-grades. After the close of the deadline for bid submission, the utility

[10] The Public Utilities Commission of the State of Colorado, *Electric Integrated Resource Planning Rules*, COPUC 4 CCR 723-21.

publicly opens the sealed bids. All responsive bids are ranked in accordance with the bid evaluation criteria and planning assumptions.

A third party oversees the process if an incumbent utility or its affiliate participates in the bid process in its own territory. The third-party overseer is nominated by the utility, approved by the Public Utilities Commission of Colorado, and paid by the utility.

Q. Is there another example of a competitive bidding program?

A. Yes. The Pennsylvania Public Utility Commission approved a program for Allegheny Power to solicit bids to supply 20 percent of the utility's hourly residential load during 2001.[11] Features of the program included: Requests for Qualification packages would be posted in newspapers and on the utility's website, bidders would have a month to submit qualification packages, each bidder had to be a domestic entity and have FERC certification as either a power broker and/or an electric utility, each bidder had to provide a letter of credit or other form of security, and the bids would be evaluated based on economic and non-economic considerations. Bid packages were to include: the proposed plan to provide the energy sources, a description of the bidder's renewable resources, a description of any pending litigation, a list of criminal convictions, a list of any civil penalties or judgements, a list of any revocations or suspension of any authority to do business, a list of actions resulted in barring from public bidding, a list of bankruptcy proceedings, financial statements, and a description of any default or noncompliance with contractual obligations.

Q. Is there an example from the natural gas industry?

A. Yes. In 1998, the Oklahoma Corporation Commission adopted rules for competitive bidding in regard to natural gas industry restructuring.[12] Natural gas utilities are to

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[11] Pennsylvania Public Utility Commission, Docket No. P-00001802, order adopted October 25, 2000.

[12] Oklahoma Corporation Commission, OAC 165:45-17-13 and OAC 165:45-17-29.

acquire citygate or aggregation point gas services through a public bidding process. Each request for competitive bid includes: the natural gas services required (including volumes, delivery dates, and term of contract), an in-service date, and a provision for interim third-party service. The gas utility and the commission staff open all sealed bids at the commission. The utility evaluates the bids and makes a decision within 30 days of the deadline for bid submittal. The utility's decision is to be made on an arm's length basis, showing no preferential treatment to its affiliate. The utility files its decision with the commission, with copies to all bidders. Unsuccessful bidders have 15 days to file a complaint. The commission determines whether the utility's decision is a departure from the criteria or is erroneous, in which event the utility is required to rebid. The rules also contain a complaint procedure.

Q. Is there an example of competitive bidding to provide standard offer electric service?

A. Yes. Since 1999, Maine's Restructuring Act has required suppliers of standard offer service to be chosen through a competitive bid process. The winning bid prices determine the standard offer prices that retail customers pay. The Maine Public Utilities Commission administers the bid process. The process consists of the following: utilities can enter wholesale contracts upon rejection of retail bids, solicitations are for all-requirements bids with specified prices through the term and bids from one to three years would be allowed, bids that are contingent on purchasing utility entitlements at specified prices are allowed, and there are security requirements. The commission delegated to its staff the determination of the following matters: content and format of RFPs, utility data to be provided to bidders, billing units to be used to compare bids, billing units upon which to base financial capability requirements, the schedule, acceptance of alternative provisions to the standard contract, eligibility and conformance of non-price portions of proposal, and acceptance of deviations from RFP requirements.[13]

[13] Maine Public Utilities Commission, Order Regarding Standard Offer Bid Process, Docket No. 2001-399, July 18, 2001.

STAFF RECOMMENDATIONS

Q. What do you recommend in regard to competitive bidding and the Commission's Retail Electric Competition Rules?

A. I recommend that the issue of a process for competitive bidding be discussed in the Generic Docket on Electric Restructuring (E-00000A-02-0051).

Q. What do you recommend specifically in regard to APS?

A. I recommend that APS submit a competitive bidding plan for Staff review and Commission approval. The plan would describe how APS would implement Staff's recommendation for interim competitive bidding that is contained in the testimony of Staff witness Matt Rowell.

Q. What types of information should be contained in the plan?

A. At a minimum, the plan should be transparent and contain the block size or sizes, price and nonprice evaluation factors, the scoring system, pricing arrangements, bidder qualifications, performance provisions, and procedures for evaluating bids from APS affiliates. The plan should also include APS' definition of emergency or short-term purchases for reliability or economic dispatch reasons and an explanation of how APS will determine the amount of new Available Transmission Capacity.

Q. When should the plan be filed?

A. The plan should be filed in this docket, for Staff review and Commission approval, within 30 days of a Commission decision on APS' variance request.

Q. Would other parties have an opportunity to comment on the proposed plan?

A. Yes. Other parties should have 14 calendar days to file comments on the proposed plan.

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Q. Does this conclude your testimony?

A. Yes, it does.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-present), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999, testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999, testimony on analysis of special contracts.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988

"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees.* Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues,"* Arizona Corporation Commission, 1997.

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A PARTIAL VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	))))	DOCKET NO. E-01345A-01-0822

DIRECT

TESTIMONY

OF

JERRY D. SMITH

ELECTRIC UTILIES ENGINEER

UTILITIES DIVISION

MARCH 29, 2002

jdsAPStestimony

TABLE OF CONTENTS

Page

EXHIBITS

INTRODUCTION

Q. Please state your name and business address.

A. Jerry D. Smith, 1200 West Washington, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer for the Utilities Division.

Q. Please summarize your educational background.

A. I graduated from the University of New Mexico in 1968 with a Bachelor of Science degree in Electrical Engineering. I received a Masters of Science degree in Electrical Engineering from New Mexico State University in 1977 majoring in power systems and electric utility management.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

Q. Please describe pertinent work experience.

A. I joined the Commission Staff in February 1999, following a 27 year career with the Salt River Project ("SRP"), one of the state's largest electric utilities. During my SRP career I:

1) analyzed and planned transmission and distribution system improvements;
2) managed design and consultation services required for retail customer projects; and
3) served as primary contact for local municipalities regarding siting of facilities and utilizing funds for aesthetic treatment of water and power facilities.

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While employed by SRP, I also performed ancillary functions such as development and management of capital improvement budgets; formation and modification of system planning, operational and maintenance policies, procedures and practices; and creation, modification and administration of new contribution in aid of construction charges and tariffs.

My responsibilities with the Commission have included involvement in Arizona's regulatory rulemaking and rate processes regarding retail electric competition and direct access of transmission and distribution facilities. I have actively participated in the organizational development of an Arizona Independent Scheduling Administrator ("AzISA") and a Regional Transmission Organization ("RTO") called Desert STAR. Desert STAR has since been replaced by a different RTO organizational form and filed with FERC as Westconnect. I was also responsible for the Commission's investigation of distributed generation and interconnections for potential rulemaking consideration.

My experience with the Commission includes providing analysis and testimony regarding quality of service issues, utility planning and siting requirements, system adequacy assessments and cost of service studies. I have also been the Commission's primary staff witness for recent power plant and transmission line siting cases.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before this Commission regarding numerous matters. I have given testimony regarding rate cases, quality of service cases, the Commission's distributed generation investigation, power plant and transmission line siting cases and electric industry restructuring and competitive market matters.

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PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in these proceedings?

A. My testimony documents the status of existing and emerging electric system infrastructure in Arizona. I will address the adequacy of Arizona's existing electric system to ensure reliable electric service to Arizona amidst a competitive wholesale market. I will further address to what degree new power plants and new transmission lines are emerging in a manner to effectively support the development of a robust competitive wholesale market in Arizona. I will conclude my testimony with a discussion of the short-term and long-term practicality of competitively bidding 50 percent of Standard Offer retail customer load per A.A.C. R14-2-1606.

Q. How have you prepared for your testimony?

A. I have reviewed information on file with the Commission in the form of annual utility operational presentations, data gathered in the Commission's first Biennial Transmission Assessment, ten-year plans, evidentiary records of power plant and transmission line siting cases, and APS responses to Staff's data requests in this case.

EXISTING ARIZONA SYSTEM INADEQUACIES

Q. Is Arizona's existing electric system adequate to ensure reliable service via a competitive market?

A. APS claims that the regional wholesale market is too thin and volatile to make it desirable for utilities to be required to depend on large new power purchases from unaffiliated suppliers at this time. Staff agrees with APS that the existing power supply margin is thin and that Arizona transmission constraints limit delivery from some new generating sites. Uncertainty regarding the numerous power plants under construction leaves the near-term wholesale market vulnerable to delays, unresolved transmission constraints or potential fuel delivery constraints. Nevertheless, Staff believes the variety of Arizona power plant and transmission projects under construction will establish a reliable and no bust Arizona wholesale market within several years.

Evidence supporting APS's claim regarding a thin wholesale market over the next few years was provided during a February 16, 2001, ACC Energy Workshop 2001 - 2002. APS presented its load forecast and expected generating resources as depicted by Exhibits JS-1 and JS-2. Concerns at the workshop focused on the fact that APS was taking extraordinary measures to develop adequate resources for 2001 and 2002 due to inadequacies of the wholesale market in the Western Interconnection ("WI"). Such measures included upgrades to existing APS combined cycle and combustion turbine units, reactivating mothballed APS steam turbine units at West Phoenix Power Plant and Pinnacle West Energy Corporation ("PWEC") placing 99 megawatts of temporary small combustion turbines units at both the West Phoenix and Saguaro plant sites. In addition, the APS resource plan was dependent upon energy from new PWEC combined cycle units at West Phoenix and Redhawk.

Even though APS has taken extraordinary steps with its affiliate to develop its own short-term resource solutions, it remains vulnerable to short-term contracts from a tight wholesale market. The short-term wholesale market is faced with prevailing adverse hydro conditions in the northwest, on-going California supply deficiencies, and natural gas supply and delivery concerns. These concerns were borne out in the summer of 2001. Precautionary steps were taken by Arizona utilities when the natural gas industry announced pending gas curtailments. Furthermore, on July 4, 2001, APS was within one half hour of activating rolling blackout procedures due to unavailability of several generating units due to repairs and the subsequent outage of the Saguaro Power Plant due to a lightning storm. Rolling blackouts were avoided when APS successfully obtained emergency short-term purchases from its neighboring utility, the Salt River Project.

Four new merchant power plants have begun commercial operations since the February 16, 2001, Energy Workshops. A technical summary of the four plants is provided as Exhibit JS-3. The total nominal capacity of these plants is 1,830 megawatts. The Griffith Power Plant and South Point Power Plant are located in Mohave County. The new PWEC combined cycle plant is located at the APS West Phoenix power plant site. Reliant's Desert Basin plant is located in Casa Grande. Each new plant has faced difficulties becoming operational over the past year. Operational testing and FERC exempt wholesale generator certification challenges normally encountered by new power plants have also been accompanied by transmission concerns for several of the new plants.

Q. Are there transmission constraints inside or outside Arizona that currently impede wholesale market access to Arizona customers during any seasons of the year or times of the day?

A. Yes, significant transmission constraints around Arizona's major load centers are another factor contributing to the thinness of the wholesale market in Arizona. Transmission constraints both inside and outside Arizona currently impede energy from the wholesale market reaching Arizona customers during summer peak hours. These constraints were reported in Staff's Biennial Transmission Assessment revised July 2001 and adopted by the Commission. The report established that three geographical load zones (Phoenix, Tucson and Yuma) are transmission import constrained at peak load conditions. These transmission import constrained geographical load zones are depicted in Exhibit JS-4.

Generation internal to these load zones "must run" at peak load conditions to avoid system overloads and voltage problems for outage of critical lines. Thus, merchant generators, which may be more cost-effective than generation available locally, are precluded from bidding to serve these areas during peak hours. Exhibit JS-5 was presented as evidence during transmission line siting Case #115 and depicts the most up to date information available to Staff regarding APS's capability to serve load within the Phoenix transmission constrained area. It is important to note that a Phoenix area load tripping scheme was implemented by APS and SRP for 2001 summer peak season and will continue through the 2002 summer peak season and until construction of the Palo Verde to Southwest Valley 500 kV line is completed. This scheme is necessary to avoid critical single contingency line outages or generator outages causing protection and control systems to interrupt other electric facilities.

Similarly, new generation capacity under construction and interconnecting at the Palo Verde commercial hub will be constrained by existing 500 kV transmission lines interconnected at the hub. The Biennial Transmission Assessment references Palo Verde Interconnection Studies that have shown that no more than 1,800 to 3,360 megawatts of new generation can be accommodated at the Palo Verde hub without transmission upgrades. This capacity is over and above the transmission capacity committed to the Palo Verde nuclear generating units. Four generating projects totaling 3,930 megawatts are currently under construction and will be interconnected at the Palo Verde hub over the next 15 months. Two of the projects totaling 1,640 megawatts are expected to be operational this summer.

Two additional transmission constraints have been identified since Staff's Biennial Transmission Assessment was completed. Both constraints were revealed during Arizona Power Plant and Transmission Line Siting Committee hearings for two new projects. Toltec Power Plant siting hearings (Case #112) revealed that the new Reliant Desert Basin Power Plant in Casa Grande could not deliver its full capacity to SRP in the Phoenix area because of 115 kV and 230 kV transmission system constraints between the plant and the Phoenix load zone. Testimony during Case #111 siting a TEP 345 kV transmission line and Citizens Communications 115 kV transmission line to serve Nogales and Santa Cruz County revealed another transmission constraint. Citizens

Communications presented a load forecast that indicated that as early as summer peak 2003 the load in Santa Cruz County may exceed the delivery capability of the existing 155 kV line serving the area. Even with the proposed new transmission line to Nogales, continuity of service to customers is of concern in case of the outage of the new line.

Q. Are owners of constrained transmission facilities, or holders of transmission rights, able to use their control to affect market prices?

A. Yes, transmission owners and holders of transmission rights can exercise market power and affect market price in a variety of ways.

In the case of transmission import constrained load zones, local generation must run during peak periods to avoid transmission system problems. When local must-run generators are old and are of a fuel source and technology that yields high operating and maintenance costs, then relying on these must-run generators can result in higher system incremental costs for energy purchases than would have occurred had there been ample transmission capacity. Such market power is further exacerbated when a single company or affiliates of a common company own both the transmission and local generation. By placing obligations on new competitive Electric Service Providers ("ESP") to share in the cost of must-run generation, an incumbent utility can cause the energy prices for competitive customers to be elevated in some instances above the shopping credit level at which the incumbent serves standard offer customers.

Market control and pricing in the case of a commercial hub such as Palo Verde that is constrained by transmission capacity takes a somewhat different form. By there not being sufficient transmission available to reliably deliver all of the output of all units connected to the hub, there is an effect of stranding some of the connected generation capacity. This has a dual effect on prices. It first can cause the interconnected power plants to primarily compete to a floor price within the hub and to offer non-firm energy where firm energy would otherwise be available. If the interconnected transmission providers are able to purchase and deliver all the energy that they need for their local consumers, then they are satisfied. However, the constraint also protects higher pricing of energy from other plants owned by affiliates of the transmission providers because the hub units cannot compete with them due to delivery constraints. Secondly, transmission constraints at a hub can cause the bidding price for transmission rights to be elevated due to transmission congestion. Arizona does not yet have such a transmission congestion pricing mechanism but proposes such a pricing mechanism when its proposed Regional Transmission Organization ("RTO"), WestConnect, becomes operational. The California Independent System Operator ("CAISO") already has such a transmission pricing mechanism in place for lines from Palo Verde to California. If a company has both a power plant affiliate and a transmission provider affiliate interconnected at such a hub, then they can certainly leverage the price of energy production versus the price of energy delivery.

EMERGING COMPETITIVE SUPPLY MARGIN IN ARIZONA

Q. Staff suggested in its power plant update to the Commissioner that a competitive supply margin is necessary for a competitive market to flourish. What is Staff's definition of "competitive supply margin?"

A. Staff believes a "competitive supply margin" exists for any given area when generation capacity within that area exceeds load, net export obligations and reserve requirements of that area by an amount sufficient to result in competitive pricing among the generators within that area. Refer to Exhibit JS-6 for a visual depiction of this concept. This model assumes all generators in the area are available to compete for wholesale market services and are not constrained by transmission capacity. Staff has not ascertained what percentage of supply margin would be necessary to ensure competitive pricing. It is Staff's belief that the composition of the area's generation portfolio regarding vintage, types of generating technology, and fuel sources would have a significant bearing on the competitive supply margin appropriate for a given area.

Q. Is a competitive supply margin emerging in Arizona?

A. It is Staff's opinion that a competitive supply margin is emerging in Arizona. The Biennial Transmission Assessment documented that 22 plants located in Arizona existed in 2000 with an Arizona utility owned capacity of 11,724 megawatts. The actual 2000 summer peak load in Arizona served by those same units was approximately 13,000 megawatts. Exhibit JS-7 depicts the status of new proposed power plants in Arizona. We are currently dependent upon import of supply from other states at peak load conditions. We are quickly moving towards a competitive supply margin in Arizona with 1,830 megawatts of new generation that became operational in 2001 and 7,210 megawatts of new generation under construction that is planned for operation by Summer 2003. An additional 5,180 megawatts of new generation has obtained ACC approval of a Certificate of Environmental Compatibility and is scheduled to come on line between 2003 and 2007. These new generating units total 14,220 megawatts of new generation in Arizona. In the same time period Arizona's peak load will grow at approximately 600-700 megawatts per year. This would yield an Arizona peak load in 2007 of approximately 18,000 megawatts, a 5,000 megawatt load growth from the year 2000 peak. The implications are that Arizona generation expansion will likely occur at a three to one ratio compared to Arizona load growth. This bodes well for establishing a robust supply margin in Arizona and allows Arizona to contribute substantially to the supply needs of the Western Interconnection.

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Q. Is the natural gas pipeline infrastructure adequate to support all proposed new gas-fired generation plants? How many plants can it support?

A. The existing gas infrastructure serving Arizona is inadequate. Staff has consistently taken such a position during power plant siting hearings. The natural gas infrastructure in Arizona at this time largely consists of El Paso Natural Gas Company's ("El Paso") northern and southern interstate pipeline systems and associated laterals. The Transwestern pipeline in northern Arizona also serves a small amount of Arizona's natural gas needs. Currently there are no appreciable instate natural gas production, natural gas storage, or liquid natural gas facilities in Arizona. Therefore, natural gas consumers in Arizona, whether residential or power generating in nature, rely on the on-going flow of natural gas on the interstate pipeline system to meet their service needs. Exhibit JS-8 depicts the gas pipeline systems and relative location of new Arizona power plants.

There is a general uncertainty regarding pipeline capacity availability for shippers on the El Paso pipeline system. The rights, obligations, and needs of shippers and El Paso are being disputed in a number of proceedings at the Federal Energy Regulatory Commission ("FERC"). At this time it is unclear how or when the disputes regarding pipeline capacity will be resolved. However, it is clear at this time that during periods of high demand, the El Paso system is unable to fully meet the needs of its existing shippers. During periods of relatively low demand on the interstate pipeline system, it appears that the system is generally able to meet the needs of its shippers. This situation exists at a time when few of the new natural gas-fired generating units are yet operational. As additional gas-fired generating units come on line in Arizona and other southwestern states that utilize the same pipeline systems, the inability of the existing pipeline system to serve all customer demands will become increasingly apparent.

El Paso has failed to address the growing demands for natural gas transportation in Arizona and the Southwest. New generating facilities appear to be relying on a number of possible sources of pipeline capacity for their facilities, including: use of existing contract rights, acquiring released pipeline capacity from other shippers, purchasing rights on new pipelines or pipeline expansions, and swapping of gas supplies on different pipeline systems.

In the long term, market players are likely to build additional pipeline capacity and/or natural gas storage capacity to serve additional demand for natural gas in Arizona and the Southwest. Exhibit JS-8 depicts two gas pipeline projects and a gas storage facility that have been announced for Arizona. However, it is unclear at this time how well the availability of additional pipeline capacity in the future will coincide with the additional natural gas demand of the new generating facilities in the next few years. The on-going uncertainty regarding existing shippers' rights on the El Paso system has made it difficult for both shippers and potential capacity expansion developers to accurately gauge what the demand/need is for additional capacity. Most new gas-fired generating units in Arizona are located near El Paso's southern pipeline system, and this is likely to be the area of greatest concern regarding the shortfall of interstate pipeline capacity, although several recently announced pipeline projects may at least partially address the shortfall.

RESOLVING TRANSMISSION CONSTRAINTS

Q. What plans are in place to relieve transmission constraints?

A. A new 500 kV line from the Palo Verde hub to the new Southwest Valley switching station has been approved in Line Siting Case #115. That line is under construction for a Summer 2003 completion. Until that line is in service, local Phoenix area generation must run during peak hours. (And thus, merchant generators located outside of the Phoenix area cannot bid to supply Phoenix during peak hours.) APS revealed in

Case #115 that APS and SRP must activate tripping schemes to drop load for a line outage or local generator outage during local peak load conditions until the new line is in service.

Pinnacle West Energy Corporation is a partner in expanding generation at the West Phoenix Power Plant. Similarly, SRP is expanding its Kyrene Power Plant and Santan Power Plant. All three projects are internal to the transmission import constrained Phoenix load zone. During the past year, two additional 500 kV transmission lines have been announced for 2006 and 2008 that will help relieve the transmission import constraint for this area: a Palo Verde to Southeast Valley Switching Station line and a Palo Verde to Table Mesa line.

APS has planned a new 230 kV line from Gila Bend to Yuma by 2006. This line will eliminate the transmission import constraint for the Yuma area. In addition, York and Welton Mohawk Irrigation and Drainage District have proposed a new Yuma area generation project for 2004. The generation project is active in the state siting process as Case #114.

In addition to the three new Palo Verde transmission lines identified above, the Commission has conditioned Duke's Arlington Valley II Power Plant with the upgrade of the Palo Verde to Kyrene and Palo Verde to North Gila 500 kV lines. A number of other Palo Verde line projects have been discussed but applications for Certificates of Environmental Compatibility ("CEC") have not yet been filed with the Commission. Public Service Company of New Mexico ("PNM") still has a transmission line from Palo Verde to Mexico under study through CATS. The PNM line is active in a federal Environmental Impact Assessment ("EIS") and Presidential Permit process with the US Department of Energy as the lead agency. There has been recent discussion of upgrading the existing Palo Verde to Devers line and building a second Palo Verde to Devers 500 kV line. Similarly, a merchant transmission project to build a 500 kV line from Gila Bend to North Gila in conjunction with other transmission enhancements in California continues to seek a funding source.

Q. How long will it take to relieve any existing transmission constraints and what factors are affecting and will affect prospects for relief?

A. Phoenix-area 500 kV transmission additions in the 2003 through 2008 time period coupled with new power plants and expansions internal to the constrained area should be sufficient to reduce dependence upon older, more costly, and higher polluting local generation through about 2008. However, Staff has yet to see transmission solutions proposed for the Phoenix area that will eliminate the transmission import constraints in the long term. Since two of the three new 500 kV lines from Palo Verde must still go through the rigors of a state line siting process, there remains some risk of public opposition for the new lines.

The Tucson transmission import area faces the same line siting risks as the Phoenix area. In fact the environmental community and public at large have already been very vocal regarding a variety of transmission projects in Central and Southern Arizona. Nevertheless, there appear to be sufficient transmission options under investigation to assure the Tucson import constraint will get resolved within the next few years.

The Yuma transmission import constrained area appears to have several competing line solutions moving forward towards a 2004 resolution. New proposed merchant generation in the local area may also offer a remedy as early as 2004. It is premature to judge how quickly the Nogales constrained area will be resolved until Citizens Communications identifies its proposed solution.

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Resolution of transmission constraints at the Palo Verde hub are the most difficult to project. Except for the new 500 kV lines proposed by Arizona transmission providers, all other transmission improvements remain very speculative and lack any definitive funding sponsor, specific scope or well-defined, in-service date. Most of these proposed 500 kV transmission projects improving the Arizona / California transfer capability will require Arizona line siting approval. At best, these projects are likely to formally emerge in the last half of this decade.

Q. Are transmission owners currently doing things that will allow them to exert more or less control in the future? If so, please detail.

A. It is Staff's opinion that Arizona transmission owners have over the past year made significant progress in planning and announcing new transmission additions to resolve perceived market power via transmission constraints within Arizona. While it will take a number of years for these new lines to be sited and constructed, there is certainly a good faith demonstration of Arizona utilities' commitment to respond favorably on a forward looking basis. The recent transition from a Desert STAR RTO to a WestConnect RTO is also reflective of a commitment to have an RTO with the authority to build transmission lines if others do not.

Q. Will the transmission system be adequate prospectively (e.g., in the next 5, 10, 15, 20 years) to deliver power from new generation plants?

A. Staff believes Arizona transmission system adequacy for new generating plants will be achieved in the last half of this decade. FERC anticipates that a regional RTO will in time be the entity responsible for ensuring the adequacy of transmission capability in the Southwest or West. FERC has suggested that some form of incentive ratemaking could be used to encourage appropriate transmission upgrades identified through an RTO planning process. The process of getting a regional planning and incentive pricing structure in place will likely take several years.

Staff is not in a position to accurately assess the adequacy of planned transmission system enhancements filed with the Commission as of January 31, 2002. Such an assessment will be rendered upon completion of a second ACC biennial transmission assessment that will commence in April.

PRACTICALITY OF COMPETITIVE BIDDING: SHORT-TERM AND LONG-TERM

Q. Please describe the competitive market model contained in the Commission's Electric Retail Competition Rules.

A. A.A.C. R14-2-1615.A requires all Affected Utilities to transfer their generation assets to another entity or affiliate such that all existing generation becomes part of the competitive wholesale market. All new generation being constructed in Arizona expands the pool of resources available in that competitive wholesale market. In addition, A.A.C. R14-2-1606.B requires investor owned utilities to purchase all of their power for Standard Offer Service via the competitive market through arm's length transactions, with at least 50 percent through a competitive bid process.

Q. What are thew implications of the Commission's competitive market objectives?

A. Exhibit JS-9 graphically depicts the implications of the Commission's competitive market model. At the present time, no competitive services are being offered in utility service areas open for competition. Therefore all customers are presently receiving Standard Offer Service from their Affected Utility. As retail competition becomes a reality, the Affected Utility's Standard Offer Services are reduced. It is reasonable to assume that within the next ten years Competitive Services could be of a magnitude that they exceed the load growth that occurs over the same time period. This would result in an Affected Utility's Standard Offer obligations being less in the future than they are at present.

The competitive market model that I have just described has several implications. It places the largest 50 percent competitive bidding requirement on the Affected Utility at the front end of the process of developing retail competition in Arizona. Such a requirement comes at a time when the Arizona wholesale market is just beginning its transition from an area supply deficit mode and moving towards a competitive supply margin. Secondly, Electric Service Providers ("ESP") that desire to commence offering Competitive Services in the Affected Utility's service area will also be seeking to secure power from the same competitive wholesale market as the Affected Utility. A robust Arizona supply margin will be required to satisfy the competing interest of Affected Utilities with a 50% competitive bidding requirement, new ESPs desiring to provide Competitive Retail Services and the Western Interconnection wholesale market at large.

Q. Are sufficient suppliers available for an effective bidding process for 50% of standard offer service? A higher or lower percentage?

A. Staff is inclined to agree with APS that the market is too thin to support an effective bidding process for 50 percent of standard offer at this time. It is important to note that this is partly because the utilities' own share of the generation market is so large. Also, transmission constraints in Arizona inhibit the ability to competitively the full 50 percent of Standard Offer at this time. Nevertheless, Staff believes that there is a sufficient market developing for Summer 2003 and new transmission planned for Summer 2003 to enable competitive bidding a substantial portion of the 50 percent of Standard Offer Services of APS.

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Q. What is the basis for Staff's proposed interim competitive bidding provisions for APS?

A. Staff advocates interim competitive bidding provisions for APS based upon consideration of three basic factors: expected existence of new generation to bid for Standard Offer Service requirements, location of load and new generation, and Arizona transmission constraints.

Exhibit JS-7 documents that 1,830 megawatts of new generation has come on line in Arizona over the past year. An additional 7,210 megawatts of generation is under construction and expected to be operational by Summer 2003. An additional 600 megawatts of generation has been approved, will commence construction shortly and is also expected to be available by Summer 2003. The total capacity of all of these new generating units is 9,630 megawatts. These new Power Plants are listed in Exhibit JS-10.

The ratio of competitive plant capacity (9,630 MW) to 50 percent APS Standard Offer Services (3,000 MW) is slightly greater than three to one. At least one of the competitive plants listed in Exhibit JS-10 is known to have contractual obligations already committing all of its capacity. Furthermore, not all of the plants are able to deliver their full output to APS Standard Offer load due to location in the system. But the W. Phoenix, Kyrene, Desert Basin, and Sundance power plants are all poised to deliver power within the Phoenix constrained load zone. These four generating plants total 1,840 megawatts. Staff does not view availability of new plants to be problematic for competitive bidding for Summer 2003.

Exhibit JS-5 reveals that approximately 4,150 megawatts of the APS 2003 peak load is located within the transmission constrained Phoenix load zone. According to data submitted by APS for the Commission's Revised Biennial Transmission Assessment report the load in the constrained Yuma area in 2003 is approximately 290 megawatts. [1] The remaining APS Standard Offer peak load for 2003 is located external to known transmission constrained load zones. Staff estimates that load to be approximately 1,600 megawatts. Staff knows of no technical reason inhibiting APS competitively bidding this 1,600 megawatts of load.

The 1,840 megawatts of new generation located internal to the Phoenix transmission constrained area has the net effect of addressing the transmission import constraint irrespective of who owns, operates or purchases the output. Simply by running these units during the summer season when the transmission system constraint exists frees up Available Transmission Capacity ("ATC") in the constrained system. If the units are scheduled to serve load within the constrained area then they reduce the amount of local load that must be served by the importing transmission system. On the other hand, if the units are scheduled to export their capacity external to the constrained load zone they offer the opportunity for a counter transmission import schedule of equal magnitude. This principle was recognized and adopted in AzISA operating protocol on file with FERC. Staff knows of no technical reason inhibiting APS competitively bidding its share of the 1,840 megawatts transmission import scheduling capability resulting from the operation of new units located internal to the transmission constrained Phoenix load zone.

In addition, APS and SRP are constructing a Palo Verde to Southwest Valley 500 kV transmission line for Summer 2003 operation that will result in an additional 1,200 megawatts of transmission import capability for the constrained Phoenix load zone. Therefore, 3,060 megawatts of new transmission import scheduling capability will exist in 2003 for the Phoenix load zone due to new generation located internal to the constraint and the new transmission line. APS and SRP have been sharing Phoenix area transmission import capability on a pro-rata basis. APS should gain approximately 1,500

[1] Revised Biennial Transmission Assessment 2000-2009, Revised July 2001, Appendix D, page 14.

megawatts of transmission import scheduling capability in 2003. Staff knows of no technical reason inhibiting APS utilization of its 1,500 megawatts share of new transmission import scheduling capability to deliver power from competitively bid generation external to the transmission constrained Phoenix area.

Staff recognizes there are risks associated with its conclusions. Staff's conclusions are dependent upon the successful implementation of many new construction projects in a very short period of time. Likewise, Staff recognizes there is considerable uncertainty relative to natural gas delivery to Arizona shippers due to matters pending at FERC. Therefore, Staff is recommending alternative interim competitive bidding provisions in Matt Rowell's testimony to better manage the risks associated with the emerging competitive market outlined in this testimony.

Q. How should the Commission and the parties view this information?

A. Although the information I have presented is factual, there are risks and uncertainties associated with the achievement of these competitive bidding objectives. There are variables in the market over which Staff, the Commission, or APS have no control. There is a dependency on the successful and timely construction of many new power plants and a transmission line in a vary short period of time. Staff recognizes there is considerable uncertainty relative to natural gas delivery to Arizona shippers due to matters pending at FERC. Therefore, Staff presents this information to provide a starting point for discussion about how competitive bidding could best be managed in the short-term.

Arizona
Corporation
Commission

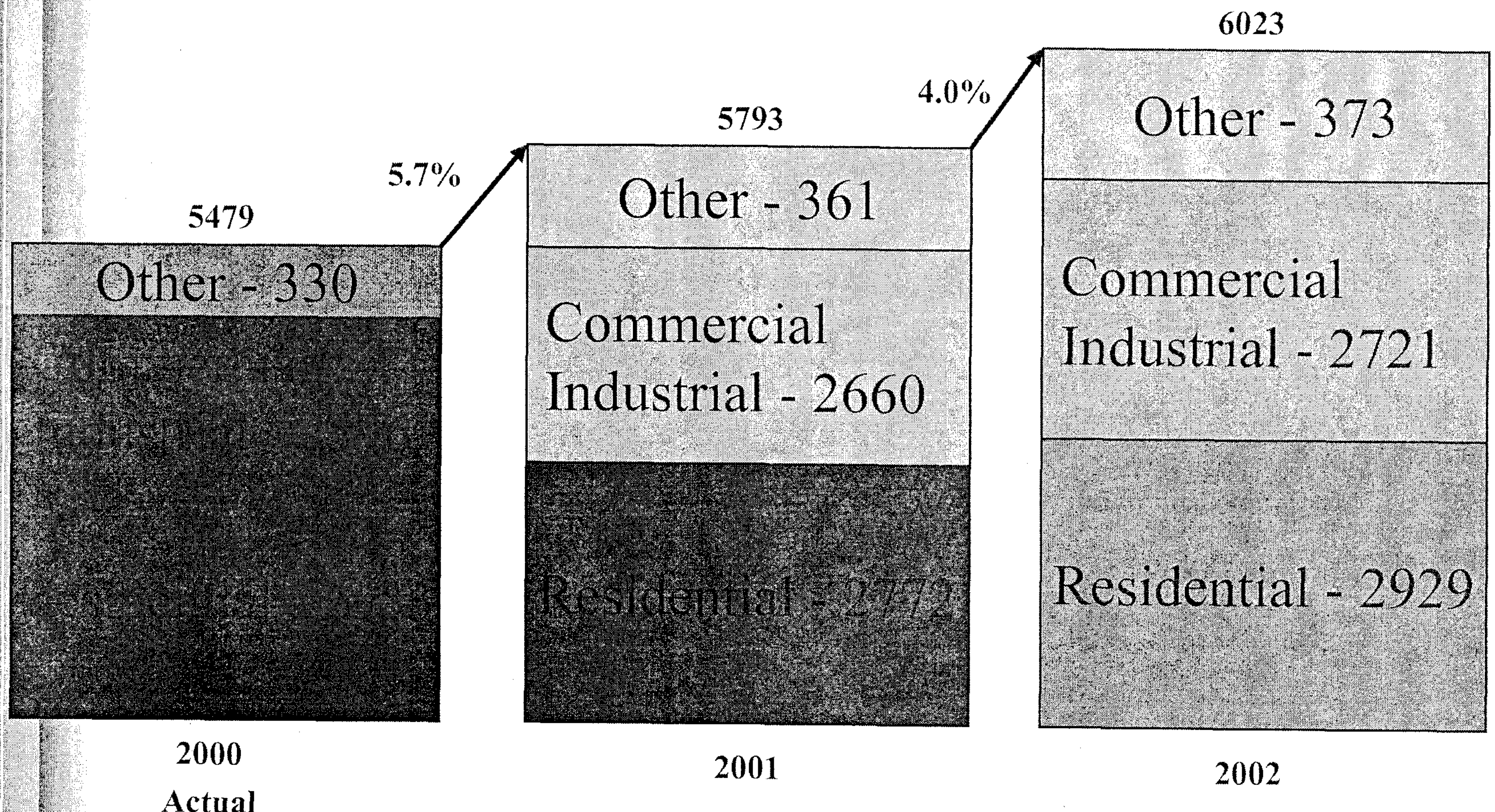
Docket No. E-01345A-01-0822

APS Request for R14-2-1606 Variance and PPA

Jerry D. Smith, ACC Staff

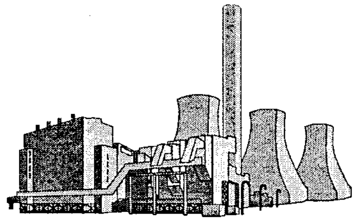
March 29, 2002

APS
Peak Load Forecast



Values in MW

Exhibit JS-1



APS Resources

	2001	2002
• Existing Generation	3982	4497
Renewable	9	13
• Additions		
Upgrade of existing CC&CT	107	-
Reactivate WPhx Steam 4&6	96	-
WPhx CC 4	114	-
Temporary WPhx CT's - 5 units	99	(99)
Temporary Saguaro CT's - 5 units	99	(99)
Redhawk CC 1&2	-	988
Subtotal	515	790
• Long-term Contracts		
Pacificorp Exchange	480	480
SRP	336	343
Subtotal	816	823
• Short-term Contracts	1176	638
• Total Resources	6498	6761

Exhibit JS-2

New Power Plants 2001

Plant	Nominal Capacity (MW)	Gas Use (MMBtu/Yr)	Water Use (Acre-Ft/Yr)
Desert Basin	520	33,100,000	4,200
Griffith	650	36,266,400	3,060
W. Phoenix	120	6,619,200	1,083
South Point	540	35,000,000	4,500
TOTAL	**1,830**	**110,985,600**	**12,843**

Exhibit JS-3

Arizona EHV Transmission

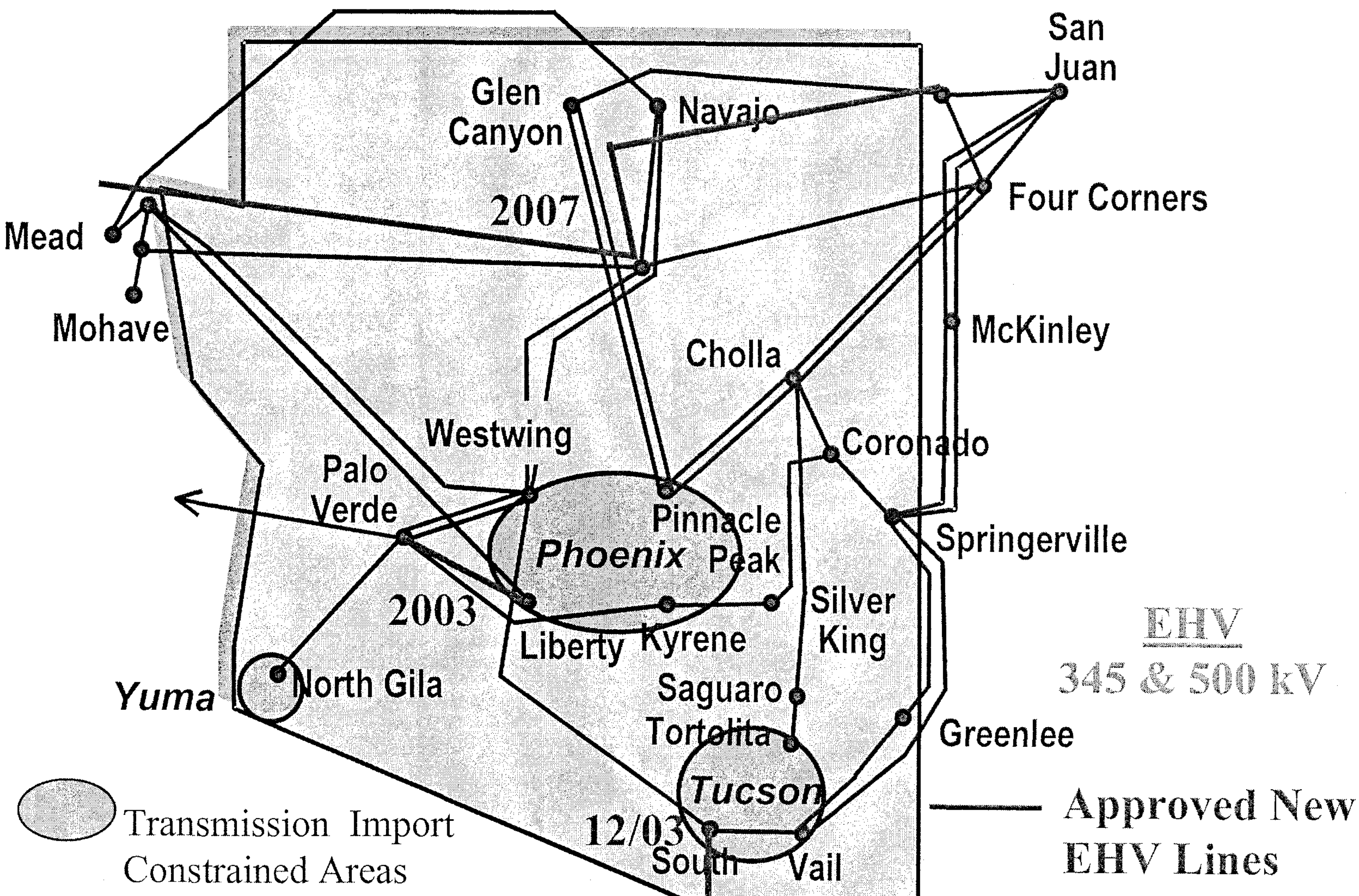


Exhibit JS-4

Case #115

Recreated in Excel using Exhibit D - 12

Districts' Second Revision Figure 14 from the Revised Biennial Transmission Assessment

APS Phoenix Metropolitan Area Load Serving Capability

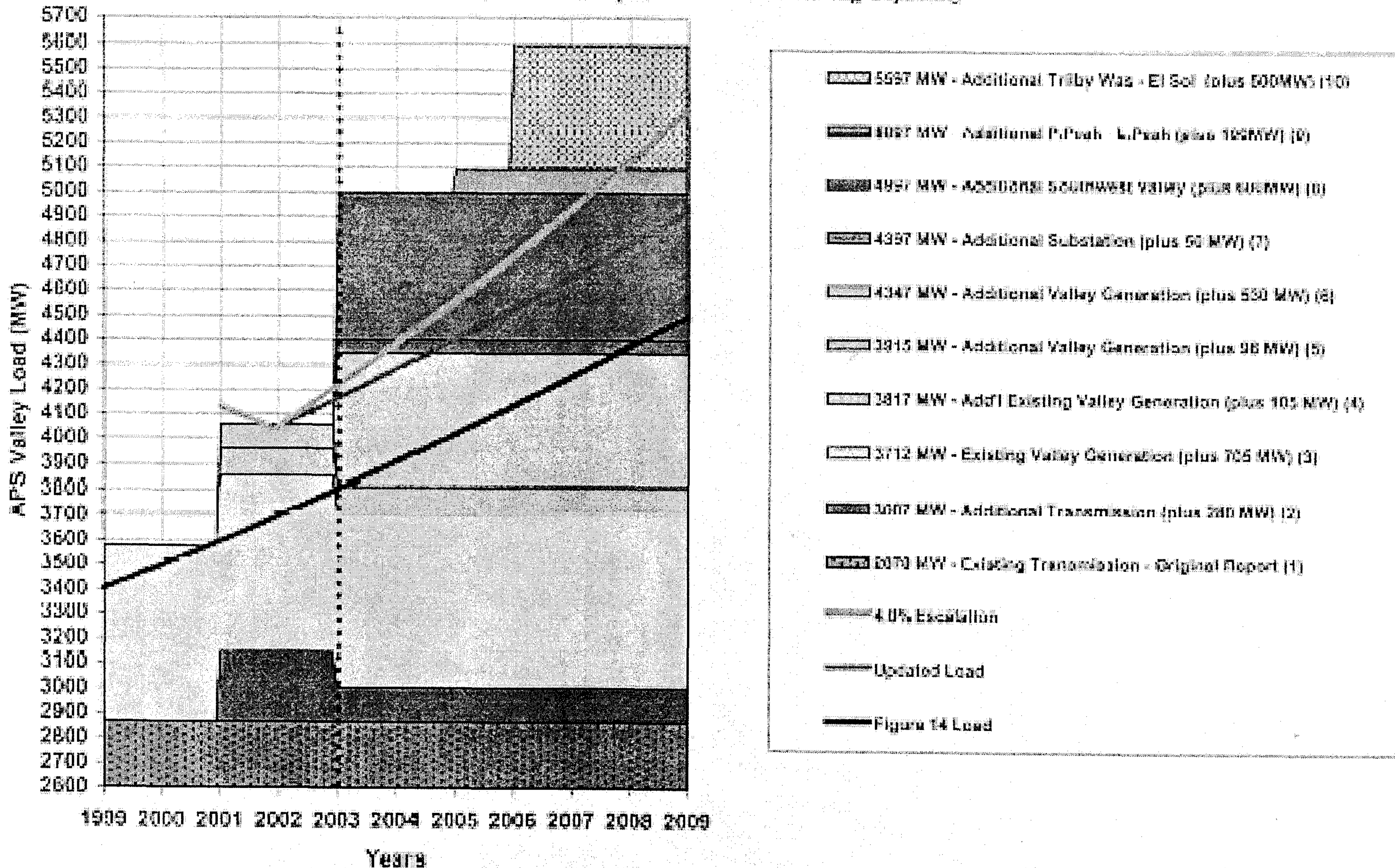


Exhibit JS-5

Competitive Generation Requirement*

Area = WSCC,
Control Area,
RTO,
State,
or Utility

Area Load
- Interruptible
+ Net Export

Reserve Load Responsibility
+ Reserves

Min. Gen. Req.
+ Comp. Supply Margin

Total Gen. Req.

Plng Reserves
Capacity Margin
Operating Reserves

* Assumes no Transmission constraint

Proposed Plants in Arizona

Status	Year							Total MWs
	2001	2002	2003	2004	2005	2006	2007	
Commercial Operation	1,830	-	-	-	-	-	-	1,830
Under Construction	-	3,880	3,330	-	-	-	-	7,210
Reg. Approval Received	-	-	600	2,105	1,325	620	530	5,180
Application Under Review	-	-	520	540	540	-	-	1,600
Application Filed	-	-	-	-	-	-	-	-
Announced	-	-	520	580	-	-	2,500	3,600
Total MWs	1,830	3,880	4,970	3,225	1,865	620	3,030	19,420

3/27/02

Note: Montezuma 520MW plant suspended plans w/o filing CEC application
Denied Projects = Big Sandy (720 MW) and Toltec (1800 MW)

Exhibit JS-7

New AZ Power Plants, Gas Supply Basins And Pipelines

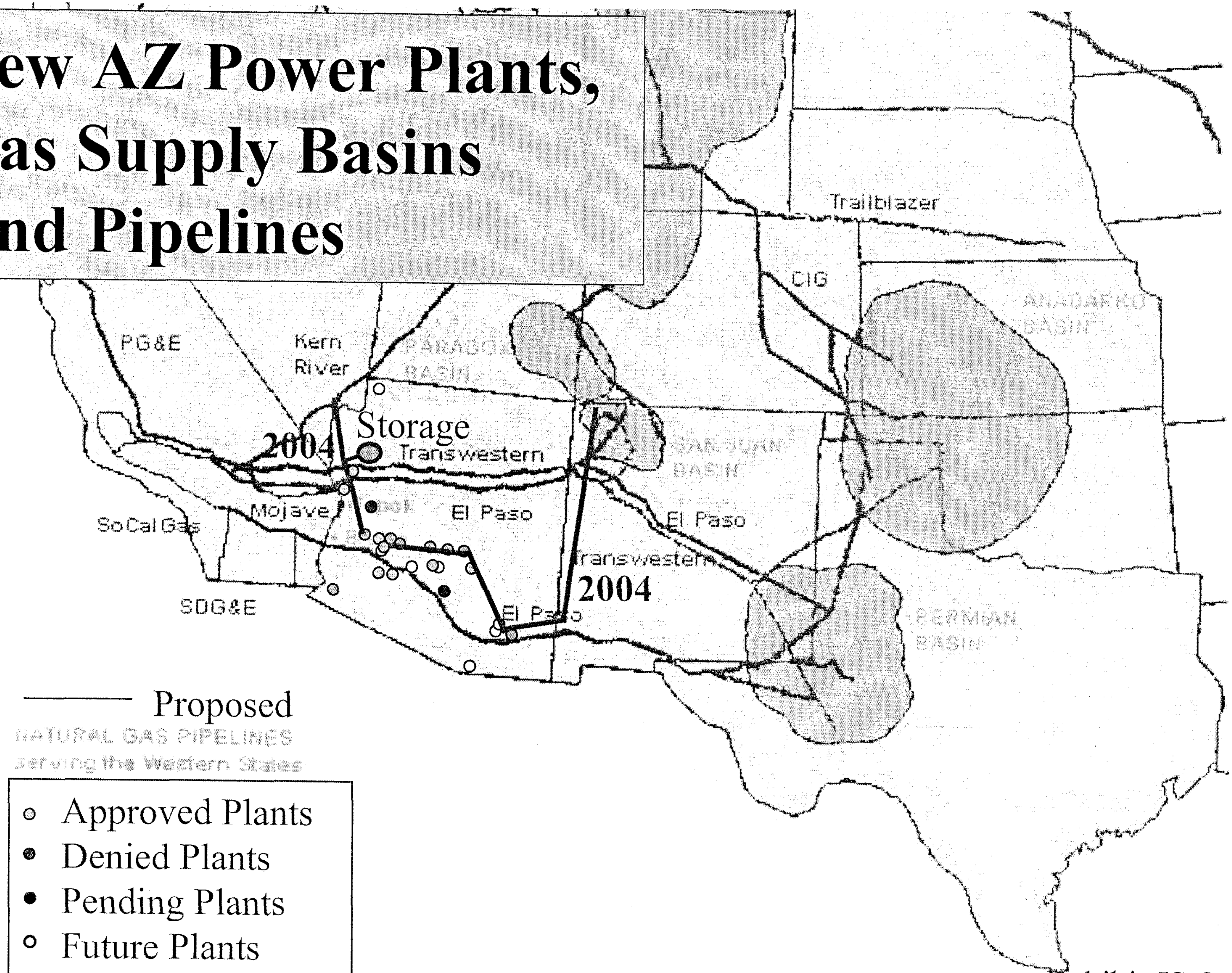


Exhibit JS-8

Competitive Market Model

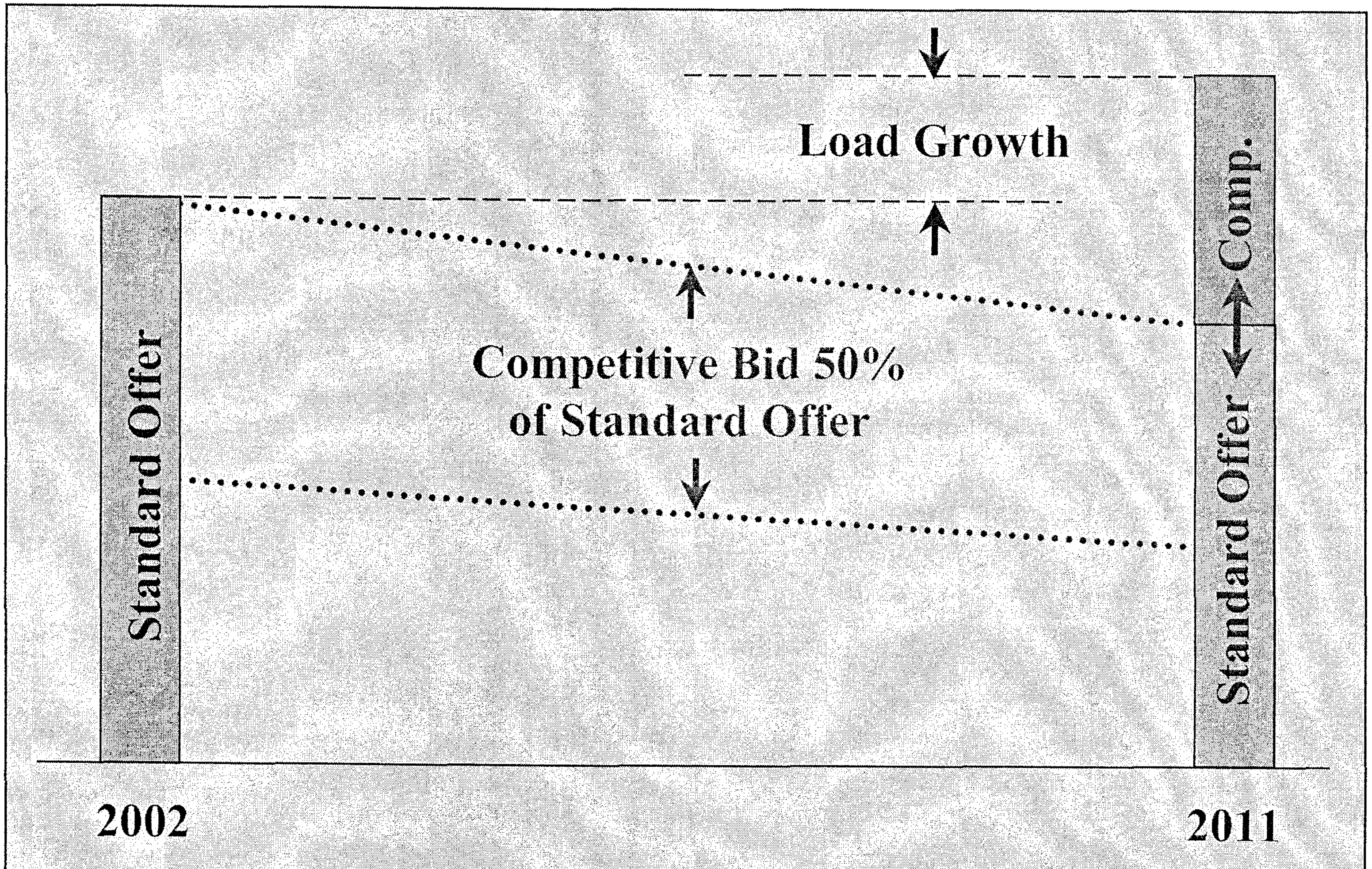


Exhibit JS-9

2003
Competitive Generation (MW)

Operational		2002	
Griffith Energy	650	Arlington Valley I	580
Desert Basin	520	Gila River 1,2	1,040
South Point	540	Kyrene	250
W. Phoenix	120	Redhawk 1,2	1,060
	1,830	Sundance CTs	450
		W. Phoenix	500
			3,880

2003

Arlington Valley II	600	Harquahala	1,040
Gila River 3,4	1,040	Mesquite	1,250
			3,930

Exhibit JS-10

BEFORE THE
ARIZONA CORPORATION COMMISSION

REDACTED

Direct Testimony of

David A. Schlissel

Docket No. E-01345A-01-0822

On behalf of

The Arizona Corporation Commission Staff

March 29, 2002

BEFORE THE
ARIZONA CORPORATION COMMISSION

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Direct Testimony of

David A. Schlissel

Docket No. E-01345A-01-0822

On behalf of

The Arizona Corporation Commission Staff

March 29, 2002

Table of Contents

I. QUALIFICATIONS

Q. Please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Staff of the Arizona Corporation Commission. ("Staff")

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in economic and policy analysis of electricity restructuring, particularly issues of consumer protection, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 24 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the California Public Utilities Commission, the Staff of the Arizona Corporation Commission, the Staff of the Kansas State Corporation Commission, the Arkansas Public Service Commission, municipal utility systems in Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

II. INTRODUCTION

Q. What is the purpose of your testimony.

A. Synapse was retained by the ACC Staff to evaluate the reasonableness of Arizona Public Service Company's ("APS")[1] proposed long-term Purchase Power Agreement between APS and its parent corporation, Pinnacle West Capital Corporation ("PWCC"). Synapse was also retained to investigate the reasonableness of APS' request for a variance from compliance with AAC Rule 1606(B) requiring that 50% of the supply resources to service Standard Offer customers be acquired through a competitive bidding process. This testimony reports the results of our evaluations and investigations of these issues.

Q. Please explain how Synapse conducted its investigations and analyses on this issue.

A. We reviewed APS' October 18, 2001 Request for a Partial Variance Approval of a Purchase Power Agreement ("APS Request") and the testimony that the Company has submitted in support of that Request. We also have submitted discovery questions to APS and have reviewed the Company's responses to those questions and to the other discovery submitted by the ACC Staff. In addition, we

[1] The term "the Company" also will be used to refer to APS and Pinnacle West Capital Corporation.

have reviewed the experiences of other utilities that have relied on competitive bidding processes to obtain the generation supplies needed to serve Standard Offer customer loads.

III. CONCLUSIONS AND RECOMMENDATION

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. Under the proposed PPA, APS' parent corporation PWCC would be guaranteed recovery of the costs of providing power to serve APS' Standard Offer customer loads for a period of 13 to 28 years without any Arizona Corporation Commission ("ACC") review of the reasonableness of those costs.

2. The proposed PPA contains formulae for the determination of the charges that APS would pay to PWCC for power that are similar to the rate case formulae used in traditional cost of service regulation but there would be no rate case scrutiny of these costs by the ACC. Instead, the charges that APS would pay under the PPA would be periodically adjusted by PWCC.

3. APS and PWCC would not be exposed to any significant risks under the PPA. In fact, APS and PWCC would gain significant benefits:

   A. The Company would be guaranteed to receive for the next 28 years a return of and on all of their investments in the Dedicated Units, the other fixed and operating costs related to these facilities, and all costs associated with obtaining competitively bid and supplemental resources.

   B. PWCC would receive a [**BEGIN CONFIDENTIAL**] [**END CONFIDENTIAL**] percent return on the undepreciated investment in the Dedicated Units and be entitled to keep 75 percent of the margin earned on all off-system sales.

C. APS would not have to provide potential competitors with access to more than 1,620 MW of its Standard Offer customer load for the potential 28 year term of the PPA.

D. APS or PWCC could terminate the PPA in 2015, 2020, or 2025 if the Company decides that it would be even more profitable to serve Standard Offer loads through a different agreement or market purchases.

4. If the PPA is approved, the ACC would not be able to rule on the reasonableness of the more than $1 billion of new generating facilities that APS is seeking to include as part of the PPA. Nor would the ACC be able to determine whether these new generating facilities are used and useful.

5. Pursuant to the PPA, APS would be able to recover all of the fixed costs for [**BEGIN CONFIDENTIAL**] [**END CONFIDENTIAL**] of new generating capacity. However, the PPA only obligates PWCC to supply 3,440 MW of this capacity in 2002 and 4,720 MW of this capacity starting in 2003 to serve APS' Standard Offer customer loads. APS would be able to sell the additional [**BEGIN CONFIDENTIAL**] [**END CONFIDENTIAL**] of capacity as part of off-system sales, even at times of system peaks. APS Standard Offer customers would then be charged for the extra costs of adding any other power that PWCC had to procure to meet the peak demands plus a reasonable reserve requirement.

6. The PPA only obligates PWCC to provide 21,090 GWH of energy from the Dedicated Units to serve Standard Offer customer loads. This represents only 43 percent of the total energy that could be produced each year by the Dedicated Units. PWCC would be free to sell the remaining energy from the Dedicated Units in off-system sales. PWCC could sell this energy to parties other than APS even if PWCC was at the same time acquiring expensive supplemental power for APS' Standard Offer customers.

7. PWCC could earn significant profits under the PPA from off-system sales to parties other than APS because they would be entitled to keep 75 percent of the margin from off-system sales where the margin is defined as the revenues received from energy sales to anyone other than APS less (a) the costs of associated fuel, transmission and ancillary services, if applicable, and (b) any other out-of-pocket costs associated with the sale. APS's Standard Offer customers would receive credit for only 25 percent of the margin.

8. APS is obligated under the PPA to pay all of the costs and expenses incurred by PWCC in supplying the power needed to serve APS' Standard Offer customer loads including the costs associated with the acquisition of the competitively bid and the supplemental power obtained by PWCC.

9. The proposed 28-year term of the PPA is unreasonably long.

10. Approval of the proposed PPA would contribute to the ACC's loss of regulatory authority over the Company's planning, construction, acquisition, and operation of generating capacity to serve APS' Standard Offer customer loads without furthering the development of an effective competitive market. This would include the authority to:

- Determine the reasonableness of the costs that APS' Standard Offer customers will pay for power and the charges that APS will pay to PWCC for the power to serve its Standard Offer customer loads.
- Investigate whether the costs of building the five new generating units that APS seeks to include in the PPA that are currently not in APS' rate base were reasonable and preclude the recovery of any unreasonable costs.
- Investigate whether the five new generating units that APS seeks to include in the PPA that are currently not in APS' rate base are used and useful and preclude the recovery of any costs related to plant that is not used and useful.
- Investigate whether obtaining power from these five new generating units is prudent.

- Examine whether APS is prudently planning to reliably serve its Standard Offer customer loads in the most cost-effective manner.
- Investigate whether APS and PWCC have properly credited off-system sales back to Standard Offer customers.
- Investigate whether the projections of operating expenses for the Dedicated Units in the PPA are reasonable and that actual operating expenses have been prudently incurred.
- Investigate whether the costs and expenses incurred by PWCC in the acquisition of competitively-bid and supplemental energy products were reasonable.

11. There is no evidence that relying on a competitive bid process to obtain over time the power to serve even 50 percent of APS' Standard Offer loads would reduce system reliability as is claimed by APS.

12. The proposed PPA would hinder the development of a competitive market.

13. APS overstates the benefits that its proposed PPA would provide in terms of rate stability.

14. APS' claim that the cumulative customer savings from the PPA through the year 2007 would be between $400 million and $1.5 billion is unrealistic and based on a number of seriously flawed assumptions.

15. The only fair and accurate way to determine what potential suppliers would charge would be to conduct the competitive bidding process and receive bids from merchant generators. This would allow the Commission to know what suppliers actually would charge for their power rather than being forced to rely on the Company's potentially inaccurate forecasts.

Q. What is your recommendation to the Commission?

A. The Commission should reject the proposed PPA between APS and PWCC because it is not in the public interest. There is no credible evidence that the PPA would provide significant benefits; the PPA would not enhance the development of a competitive market; and the PPA would create significant risks for APS' Standard Offer customers.

IV. DISCUSSION

Q. Please summarize the terms of the proposed PPA.

A. Under the proposed PPA, PWCC would supply power to provide all of APS' Standard Offer loads, excluding (1) power that would be supplied to APS from the PacifiCorp and SRP purchase power agreements that cannot be transferred to Pinnacle West Energy Corporation ("PWEC"); (2) power provided by APS from renewable resources in the Environmental Portfolio Standard assets; and (3) power from Qualified Facilities and other forms of distributed generation that APS is required to purchase. PWCC would obtain the needed power from a combination of: (1) generating facilities transferred to PWEC from APS; (2) five generating units constructed or being constructed by PWEC during the years 2001-2004; (3) power procured by PWCC from dedicated purchase power contracts; and (4) power procured through a competitive bid process. PWCC also would make supplemental power purchases if the power provided by the other sources was insufficient to serve APS' Standard Offer loads. The competitive bid obligation would start at 270 MW in 2003 and increase by 270 MW each year to a maximum of 1,620 MW in 2008 which would be 23 percent of APS' 2008 peak load.

The generating units that would be transferred from APS to PWEC and the five units that PWEC is constructing are collectively designated the Dedicated Units in the PPA. PWEC would obtain the output from these Dedicated Units through an agreement with PWEC.

The PPA would run through 2015 with three optional five-year renewal periods. The PPA would be automatically renewed unless notice is given by APS or PWCC. In any event, the PPA would end in 2030.

Q. What payments would APS be obligated to make to PWCC for capacity and energy provided from the Dedicated Units?

A. APS would be required to make monthly payments to PWCC for Facilities Charges, Base Fuel Charges and beginning March 1, 2003, a Fuel and Purchased Power Adjustment factor.[2]

Q. What costs would PWCC be able to recover and APS be required to pay as part of the monthly Facilities Charge?

A. Attachment #1 to the Service Schedule in the PPA establishes a formula by which the Facilities Charge would be determined every three years.[3] This formula is the same as the rate case formula that is used to determine reasonable and recoverable costs in traditional cost of service regulation but there would be no Commission review of these costs under the PPA.

Pursuant to this formula in the PPA, PWCC would be entitled to recover: (1) a specified rate of return times the net Dedicated Units Assets value and (2) the Dedicated Units Operating Expenses minus (3) annual Ancillary Service Revenues.

Q. How would the net Dedicated Units Assets value be calculated?

A. The net Dedicated Units Assets value would be calculated according to the following formula:

Net Dedicated Units Assets = Original Plant-in-Service Cost – Accumulated Depreciation – Accumulated Deferred Income Taxes + Materials & Supplies + Prepayments + Working Cash + Miscellaneous Deferred Credits.

As can be seen, the Net Dedicated Units Assets value essentially represents what the rate base value of the Dedicated Units would be under traditional regulation.

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2 Purchase Power Agreement, Section 3.2.2 at page SS 3 of the Service Schedule.

Q. Are all of the Dedicated Units currently in APS' rate base?

A. No. Although almost all of the Dedicated Units are currently in rate base, APS also is seeking to recover the costs of five new generating units that are not currently included in rate base. The total investment associated with these five units is more than $1 billion.[4]

Q. Has the Company performed any economic analyses to examine whether these five new units are the most cost-effective option for reliably serving APS loads?

A. No. APS has said that no such specific analyses were performed.[5]

Q. Under the PPA would the Arizona Corporation Commission have any opportunity and the regulatory power to investigate whether the costs of building these five new units were reasonable and to preclude the recovery of any such unreasonable costs through the PPA?

A. No. There would be no Commission jurisdiction over the prudence and reasonableness of these investments. Consequently, the Commission would not have any opportunity to examine the reasonableness of the more than $1 billion in new plant investments that APS is seeking to recover through the PPA.

Q. Under the PPA would the Commission have any opportunity to investigate whether the five new generating units that APS is seeking to include as Dedicated Units are used and useful and to preclude the recovery of any costs related to plant that is not used and useful?

A. No.

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[3] The initial values of the Facilities Charges for the years 2002, 2003, and 2004 are established in Section 3.2.2.1 of the Purchase Power Agreement at page SS 3 of the Service Schedule. The formula will be used starting in 2005.

[4] APS response to ACC Staff's Fourth Set of Data Requests, Question No. DS 4.12.

[5] APS response to ACC Staff's Fourth Set of Data Requests, Question No. DS 4.24.

Q. Under the PPA would there be any Commission oversight of the planning by PWCC and PWEC for serving APS' Standard Offer loads?

A. No. There would be no opportunity for the Commission to examine whether PWCC and PWEC are prudently planning to reliably serve APS' Standard Offer customer loads in the most economic manner.

Q. What is the total capacity of the APS generating plants that are included as Dedicated Units in the PPA?

A. The ten generating facilities (with a total of 39 units) would have a total summer generating capacity of **[BEGIN CONFIDENTIAL]** **[END CONFIDENTIAL]**

Q. Would the Monthly Facilities Charges that APS would pay to PWCC under the PPA provide a return of and on the undepreciated investments in all of these ten generating facilities?

A. Yes. The Monthly Facilities Charges that APS would pay to PWCC also would include all of the other fixed and non-fuel operating costs of these generating facilities.

Q. Is PWCC required under the PPA to commit all of the [BEGIN CONFIDENTIAL] [END CONFIDENTIAL] of capacity from the Dedicated Units to serve APS' Standard Offer customer loads?

A. No. PWCC is required under the PPA to provide "Dedicated Energy Products from the Dedicated Units and the Dedicated Contracts to serve APS' Full Load Requirements."[6] However, there is no requirement in the PPA that PWCC commit all of the capacity from the Dedicated Units to serve APS' Standard Offer customer loads. In fact, Section 3.2.3.1 of the Service Schedule in the PPA only commits PWCC to the following:

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[6] Purchase Power Agreement, Service Schedule, Section 3.2, at page SS 2.

> Capacity . At a minimum, PWCC shall make Capacity from the Dedicated Units available as follows: (a) for 2002, prior to the transfer of Palo Verde Nuclear Generating Station Assets, the lesser of 3440 MW at system peak or actual load at system peak; and (b) for 2003 and later, after the transfer of Palo Verde Nuclear Generating Station Assets, the lesser of 4720 MW at system peak or actual load at system peak, subject to adjustment as Dedicated Units are retired.[7]

Consequently, if it chooses to do so, PWCC could provide more than 4,720 MW of capacity from the Dedicated Units to serve APS' Standard Offer customer loads but is not required to do so by any provision in the PPA.

Q. What would PWCC be able to do with the additional [BEGIN CONFIDENTIAL] [END CONFIDENTIAL] of capacity that it would not be obligated to provide to APS to serve the Standard Offer customer loads?

A. APS has said that it would use this additional capacity to provide needed system reserves.[8] However, there is no language in the PPA that would prevent PWCC from selling some or all of these [**BEGIN CONFIDENTIAL**] [**END CONFIDENTIAL**] of capacity through off-system sales to parties other than APS, even though the APS' Standard Offer customers would be paying Monthly Facilities Charges that included all of the fixed and operating costs (including a return on the net Dedicated Units Assets) for the entire [**BEGIN CONFIDENTIAL**] [**END CONFIDENTIAL**] of the capacity from the Dedicated Units. Indeed, APS has acknowledged that PWCC might make such off-system sales to the extent that this additional capacity is not needed by APS.[9]

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7 Purchase Power Agreement, Service Schedule, Section 3.2, at page Revised SS 4.

8 APS response to Informal ACC Staff Discovery Question No. 2. submitted on March 22, 2002.

9 APS response to Informal ACC Staff Discovery Question No. 2. submitted on March 22, 2002.

Q. Earlier you mentioned that under the PPA, PWCC would make Supplemental Purchases if the committed capacity from the Dedicated Units, the Dedicated Contracts, and the Competitively Bid resources were not adequate to meet system loads. Is there any language in the PPA that would prevent PWCC from selling some or all of the [BEGIN CONFIDENTIAL] [END CONFIDENTIAL] of additional capacity from the Dedicated Units that is not committed to serving APS' Standard Offer customer loads as part of off-system sales at the same time that it is making supplemental power purchases to obtain capacity needed to serve APS' Standard Offer customer loads or to provide needed system reserves?

A. No. As the PPA is currently written, PWCC would be able to sell any additional output from the Dedicated Units above the 4,720 MW it is committed to providing through the PPA even at the time of the system peak. This means that PWCC could be selling capacity to make additional profits for the Company at the very same time it is purchasing expensive supplemental power to meet APS' Standard Offer customer loads.

Q. Who would benefit in this situation and who would bear additional costs?

A. PWCC could earn significant profits in this situation because, as I will discuss later in this testimony, under the PPA PWCC will be entitled to keep 75 percent of the margin earned from off-system sales where the margin is defined as "the revenue received from energy sales to anyone other than APS from the Dedicated Units less: (a) the costs of associated fuel, transmission and Ancillary Services if applicable, and (b) any other out-of-pocket costs associated with the sale."[10]

APS' Standard Offer customers, however, could pay very substantial costs because in addition to already having paid all of the fixed and non-fuel operating costs for the Dedicated Units they would also have to pay all of the costs associated with obtaining the supplemental power. The cost of this supplemental

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[10] Purchase Power Agreement, at page 33.

power could be very high as it is reasonable to expect that the supplemental purchases will have to be made during the periods of the greatest demand and, therefore, the highest prices. The only relief that APS' Standard Offer customers would receive under the PPA would be a credit of 25 percent of the margin earned from the off-system sales of the output from the Dedicated Units that was not used to serve their loads.

Q. Does APS acknowledge that PWCC could sell the additional power from the Dedicated Units as part of off-system sales even if PWCC at the same time had to make supplemental power purchases to meet APS' Standard Offer customer loads?

A. No. APS has claimed that the proposed PPA requires PWCC to give first priority to supplying APS' standard offer load on an hourly basis out of the Dedicated Units.[11] However, I find no such language in the Purchase Power Agreement. Although Section 1.2(A) of the PPA does obligate PWCC to providing "Dedicated Energy Products on a firm basis, and shall include adequate reserves to satisfy Good Utility Practice," Section 3.2.3.1 in the Service Schedule limits that obligation to the lesser of 4,720 MW or actual load at system peak.[12] There is no language in the PPA requiring PWCC to give first priority to supplying APS' Standard Offer customer loads from the output of the Dedicated Units.

APS also has claimed that any market risks associated with off-system sales are assumed by PWCC.[13] However, there does not appear to be any language in the PPA that specifically places this risk on PWCC or that would protect APS' Standard Offer customers against having to pay for the costs of purchasing supplemental power that would be acquired at the same time that PWCC was selling capacity from the Dedicated Units.

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11 APS' response to ACC Staff Fourth Set of Data Requests, Question No. DS 4.20(a).

12 Power Purchase Agreement, at page 1, and Service Schedule, at Revised Page SS 4.

13 APS response to Informal ACC Staff Discovery Question No. 2. submitted on March 22, 2002.

Q. Is PWCC required under the PPA to commit all of the energy from the Dedicated Units to serve APS' Standard Offer customer loads?

A. No. Section 3.2.3.2 of the Service Schedule in the PPA limits the amount of energy that PWCC is required to provide from the Dedicated Units:

> Energy. At a minimum, PWCC shall have Energy from the Dedicated Units in the amount of: (a) for 2002, prior to the transfer of Palo Verde Nuclear Generating Station Assets, 15, 370 GWh annually; and (b) for 2003 and later, after the transfer of Palo Verde Nuclear Generating Station Assets, 21,090 GWh annually, subject to adjustment as Dedicated Units are retired.[14]

Q. Do these 21,090 GWh represent APS's total retail energy sales for any future years?

A. No. These 21,090 GWh would provide 78 percent of APS' projected Standard Offer energy requirements in 2003. This percentage would decrease steadily over the years, reaching 67 percent in 2008, and 55 percent by 2015.

Q. Where would PWCC obtain the remaining energy needed to serve APS' Standard Offer loads?

A. PWCC would provide the remaining energy from the Dedicated Contracts, Competitively Bid resources, through Supplemental Purchases, and, if it chooses, PWCC could provide additional energy generated at the Dedicated Units.

Q. Is it reasonable to expect that the Dedicated Units will generate more than 21, 090 GWh each year?

A. Yes. The 21,090 GWh requirement in the PPA represents only a 42.7 percent composite capacity factor for the ten Dedicated Units. Consequently, PWEC should be able to generate significantly more than 21,090 GWh each year at these units.

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14 Purchase Power Agreement, Service Schedule, page SS 4.

The availability of this additional output would enable PWCC to make substantial off-system sales of the output from the Dedicated Units in both peak and non-peak periods. As I have explained earlier, PWCC would even be able to make such off-system sales if it were simultaneously purchasing supplemental power to serve APS' Standard Offer loads.

Q. Would PWCC be able to sell as part of off-system sales any energy generated at the Dedicated Units in excess of the 21,090 GWh annual commitment in the PPA?

A. Yes. If it chooses, PWCC could sell to APS any of the additional energy generated at the Dedicated Units in excess of 21,090 GWh. However, there is nothing in the PPA to prevent PWCC from selling any such additional energy as part of off-system sales to parties other than APS.

Q. Would PWCC be required to credit any off-system sales to reduce the amounts paid by APS through the Monthly Facilities charge?

A. No. APS has said that the monthly Facilities Charge would not be credited to reflect such off-system sales. However, an adjustment would be made to the Fuel and Purchased Power Adjustment factor contained in the PPA based on such off-system sales.[15]

Q. Would APS and its Standard Offer customers receive full credit for such off-system sales through an adjustment in the Fuel and Purchased Power Adjustment factor in the PPA?

A. No. The formula for the Fuel & Purchased Power Adjustment factor established in Attachment #2 to the Service Schedule in the PPA clearly shows that APS and its Standard Offer customers would receive a credit for only 25 percent of the off-system sales margin. This 25 percent credit from off-system sales would be calculated as follows:

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[15] APS response to ACC Staff Data Request No. 4, Question No. DS 4.20(c).

Off-System Sales Margin = [(Off-System MWh X (Price $/MWh – Average Fuel Cost for the Dedicated Units) – Other costs] X .25[16]

Consequently, APS' Standard Offer customers would be required to pay all of the fixed costs and non-fuel operating expenses for the Dedicated Units (including the return of and on undepreciated investments) but would receive only 25 percent of the margin from the off-system sales of output from these Units.

Q. How are the recoverable Dedicated Unit operating expenses calculated in the PPA?

A. The PPA establishes the following formula that would be used every three years to project a three year average for the Dedicated Units Operating Expenses.

Dedicated Units Operating Expenses = Operation & Maintenance Expenses + Administrative & General Expenses + Depreciation & Amortization Expenses + Ad Valorem Taxes + Income Tax Expense + Other Taxes or Assessments.[17]

This is the same formula that has been used to determine recoverable expenses in traditional cost of service regulation.

Q. Is there any mechanism in the PPA to ensure that these Operating Expenses are reasonable or would be prudently incurred?

A. No. In fact, it appears from the PPA that APS' Standard Offer customers would be charged for the projected operating expenses of the Dedicated Units rather than the actual expenses. There does not seem to be any mechanism in the PPA to protect ratepayers against having to pay for projected levels of operating expenses that are not actually paid.

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16 Purchase Power Agreement, Service Schedule, Revised Attachment #2.

17 Purchase Power Agreement, Service Schedule, Revised Attachment #1.

Q. Would the ACC have any jurisdiction to ensure that these three year projections were reasonable or prudently incurred?

A. No. There would be no opportunity for the ACC to investigate the reasonableness of the projected Dedicated Unit operating expenses or whether actual expenses were different from projected.

Q. Is APS obligated to pay all of the costs associated with the acquisition of the competitively bid and supplemental power obtained by PWCC to serve APS's Standard Offer loads?

A. Yes. Section 3.1.4 of the Service Schedule in the PPA obligates APS to pay any and all costs and expenses incurred in the acquisition of any Energy Products supplied through the Competitive Bidding Process including PWCC's administrative expenses associated with bid development and evaluation, and procurement.[18] Section 3.3 similarly obligates APS to pay for any and all costs incurred in the acquisition of any Supplemental Energy Requirements supplied, including PWCC's administrative expenses incurred for procurement.[19] All of these costs would be passed through to APS' Standard Offer customers.

Q. Would the ACC have any regulatory oversight concerning the reasonableness of the costs and expenses incurred by PWCC in the acquisition of this competitively bid and supplemental energy?

A. No.

Q. Would APS or PWCC be exposed to any significant risks under the PPA?

A. No. In fact, APS and PWCC would gain significant benefits from the PPA. First, the Company would be guaranteed to receive for the next 28-years a return of and on all of their investments in the Dedicated Units plus the other fixed and operating costs related to these facilities, and all costs associated with the

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[18] Purchase Power Agreement, Service Schedule, at page SS 2.

[19] Purchase Power Agreement, Service Schedule, at page Revised SS 4.

obtaining of competitive-bid and supplemental resources. At the same time, PWCC would receive a **[BEGIN CONFIDENTIAL]** **[END CONFIDENTIAL]** percent return on the undepreciated investment in the Dedicated Units and be entitled to keep 75 percent of the margin earned on all off-system sales.

In addition, APS would not have to provide potential competitors with access to more than 1,620 MW of its Standard Offer customer load for the entire 28 year period. Finally, APS or PWCC could terminate the PPA in 2015, 2020, or 2025 if the Company decides that it would be even more profitable to serve Standard Offer loads through a different agreement or market purchases.

Q. Is the potential 28-year term of the proposed PPA reasonable?

A. No. The proposed 13 to 28-year term of the PPA is far too long given the changes that are occurring in the electric industry.

Q. Please summarize the regulatory oversight authority that the ACC would be losing if it approves the PPA?

A. Approval of the proposed PPA would contribute to the ACC's loss of regulatory authority over the Company's planning, construction, acquisition, and operation of generating capacity to serve APS' Standard Offer customer loads without furthering the development of an effective competitive market. This would include the authority to:

- Determine the reasonableness of the costs that APS' Standard Offer customers will pay for power and the charges that APS will pay to PWCC for the power to serve its Standard Offer customer loads.
- Investigate whether the costs of building the five new generating units that APS seeks to include in the PPA that are currently not in APS' rate base were reasonable and preclude the recovery of any unreasonable costs.
- Investigate whether the five new generating units that APS seeks to include in the PPA that are currently not in APS' rate base are used and useful and preclude the recovery of any costs related to plant that is not used and useful.

- Investigate whether obtaining power from these five new units is prudent.
- Examine whether APS is prudently planning and purchasing to reliably serve its Standard Offer customer loads in the most cost-effective manner.
- Investigate whether APS and PWCC have properly credited off-system sales back to Standard Offer customers.
- Investigate whether the projections of operating expenses for the Dedicated Units in the PPA are reasonable and that actual operating expenses have been prudently incurred.
- Investigate whether the costs and expenses incurred by PWCC in the acquisition of competitively bid and supplemental energy products were reasonable.

Q. Do you agree that relying on a competitive bid process would reduce system reliability as is claimed by APS?[20]

A. No. APS could develop a fuel diverse portfolio of baseload, intermediate and peaking capacity by using its own facilities and the resources obtained through a competitive bid process. There is simply no evidence that adhering over time to the requirement that APS obtain the resources needed to provide 50 percent of its Standard Offer customer load would adversely affect the reliability or security of the electric system in Arizona. Numerous utilities around the U.S. now rely on resources obtained through competitive bid processes to serve more than 50 percent of their Standard Offer loads. I am not aware of any evidence that the reliability of the service provided by these utilities has been adversely affected.

Q. Do you think that obligating PWCC through the PPA to be the wholesale "provider of last resort" would provide any significant benefits?[21]

A. No. APS already is the provider of last resort for its Standard Offer customers. APS witness Davis creates a distinction without any significance when he says that obligating PWCC, APS' parent corporation, with the responsibility of being

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20 For example, see the APS Request at page 8, the testimony of APS witness Landon at page 10, lines 18 and 19, and page 11, lines 1-4, and the testimony of APS witness Davis, at pages 19 to 22.

21 Testimony of APS witness Davis, at page 2, lines 6-9.

the wholesale provider of last resort would provide significant benefits. It is entirely possible that the same personnel will be responsible for acquiring the power to serve APS' Standard Offer loads whether APS or PWCC is designated as the provider of last resort.

Q. Please comment on APS' claim that the proposed PPA will not negatively impact the development of a competitive market.

A. The claim that the proposed PPA would not negatively impact competition is patently false. The PPA would limit competitors to providing only 4.4 percent of APS' Standard Offer loads in 2003. Although this access would increase to a maximum of 23 percent in 2008, it would then decrease over the years to 18 percent in 2016 and 12 percent by 2030. This limited access to APS' Standard Offer loads can be expected to have an adverse impact on the interest of potential competitors to build new facilities to serve loads within Arizona (and perhaps their access to the capital needed to build such facilities) and would hinder the development of a competitive market.

At the same time, the PPA would require APS' Standard Offer customers to pay 100 percent of the fixed and operating costs of the Dedicated Units. This could provide a potential competitive advantage to PWCC when it is bidding against merchant generators to serve non-APS loads. This also would discourage the development of a truly competitive market.

It also is unclear whether the PPA would enable APS and PWCC to tie up needed transmission resources into and around the Phoenix area. To the extent that they were able to do so because of the existence of the PPA, potential competitors would be disadvantaged and the development of a truly competitive market would be hindered.

In addition, the PPA would pre-empt the requirement to serve Arizona load first that is being included in the Certificates of Environmental Compatibility being issued by the State's Power Plant and Transmission Line Siting Committee for new merchant power plants in Arizona:

> Applicant shall first offer wholesale power purchase opportunities to credit-worthy Arizona load-serving entities and to credit-worthy marketers providing serving to those Arizona load-serving entities.[22]

Q. Please comment on APS' claim that relying on a competitive bidding process for 50 percent of the resources needed to serve APS's Standard Offer customer loads cannot result in anything other than "very significantly more volatile and potentially much higher costs to serve Standard Offer customers."[23]

A. APS overstates the benefits that its proposed PPA would provide in terms of rate stability. First, the extreme natural gas price volatility discussed by APS and its witnesses is not currently expected to recur. But if it does, the portfolio that PWCC would provide through to the PPA also would be dependent on natural gas-fired plants for a significant amount of the energy provided to APS' Standard Offer customers. For example, APS witness Hieronymus has said that natural gas will provide approximately 30 percent of the energy to be supplied under the PPA by the Dedicated Units.[24] By the year 2008, 23 percent of the Standard Offer load will be served by energy supplied through the competitive-bid process. It is reasonable to expect that this energy also would be generated at natural gas-fired units. It is also reasonable to expect that the supplemental energy that PWCC would need to purchase to serve Standard Offer customers also would, at least in large part, be generated at natural gas-fired facilities. Consequently, by 2008, substantially more than 50 percent of the power provided under the PPA could be generated at natural gas-fired plants.

In addition, it is possible that the performance of the Company's older coal-fired units might deteriorate as a result of plant aging, thereby making the PPA even

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22 Decision of the Arizona Power Plant and Transmission Line Siting Committee and Certificate of Environmental Compatibility in Case No. 112, issued on December 6, 2001, at page 7.

23 APS Request, at page 8, lines 9-11.

24 Testimony of APS witness Hieronymus, at page 5, lines 5-6.

more dependent upon power from natural gas-fired plants than the approximately 30 percent reliance cited by Mr. Hieronymus.

Finally, given the length of the proposed PPA, it also is possible that that the coal price advantage cited by Mr. Hieronymus could erode as a result of the adoption of stricter environmental regulations or climate change policies affecting coal-fired facilities.

Q. How old is the Company's fossil-fired generating capacity?

A. Four of the Company's coal-fired generating units[25] and six of the Company's natural gas-fired units,[26] representing a total of 1,196 MW of summer capacity, are more than 38 years old. Another two of APS' coal-fired and six of its natural gas-fired generating units, representing 436 MW of summer capacity, are between 30 and 37 years old.[27]

Q. Please comment on APS' claim that cumulative customer savings under the PPA would be between \$400 million and \$1.5 billion through the year 2007.[28]

A. This claim is unrealistic and based on a number of seriously flawed assumptions. First, APS compares the cost of generating 25,000 GWh of output from its Dedicated Units against the cost of producing the same output from new natural gas-fired facilities. However, it would require approximately 5,600 MW of new merchant capacity, operating at the stated 51 percent load factor, to produce this 25,000 GWh of output. This would be far more than the 3,000 MW of capacity that actually would have to be provided by merchant generators if APS were to comply with the 50 percent competitive bidding requirement of Rule 1606 and also would be significantly more capacity than APS has said would be available

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25 Cholla Unit 1, Four Corners Units 1-3.

26 West Phoenix Units 4 ST and 6 ST, Ocotillo Units 1 ST and 2 ST, Saguaro Units 1 ST and 2 ST.

27 Four Corners Units 4 and 5, West Phoenix CT1, Ocotillo 1 CT, Saguaro Unit 1 CT, Douglas 1 CT, and Yucca Units 1 CT and 2 CT.

28 Testimony of APS witness Davis, at page 25, lines 15-20.

from merchant facilities in the near term to serve Standard Offer loads in its service area.[29]

Second, the APS comparison also assumes that if the PPA is not approved, 100 percent of the power that would be generated at Dedicated Units under the PPA instead would be generated at natural gas-fired plants. This is a completely unrealistic assumption. If the PPA is not approved, APS still will have to provide the power to serve at least 50 percent of its Standard Offer customer load. There is no logical reason to assume that APS would generate all of this power at its new natural gas-fired units with no power coming from its existing plants. Instead, APS would certainly serve its Standard Offer loads with power from a mix of its existing nuclear, coal, and natural gas-fired units and the new gas-fired units that PWEC currently has under construction.

Third, it is impossible to foresee what the cost of providing power actually would be under the PPA. All of the variable costs terms in the PPA are subject to adjustment, including the prices that would be paid for competitively bid and supplemental power. The fuel costs for APS' existing fossil-fired Dedicated Units also are subject to variability based on market prices. The Dedicated Units' non-fuel operating expenses also could be higher than the Company currently projects.

Fourth, APS and its witnesses make various projections of the prices that merchant generators would charge if a competitive bidding process were held for the power to serve part of APS' Standard Offer loads. However, the only fair and accurate way to determine what potential suppliers would charge would be to conduct the competitive bidding process and receive bids from merchant generators. This would allow the Commission to know what suppliers actually would charge for their power rather than being forced to rely on potentially inaccurate forecasts.

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29 For example, see page 3, lines 14-18, of the APS Request and the Testimony of APS witness Davis, at page 6, lines 6-15.

Q. Does APS witness Hieronymus' comparison of the proposed PPA with the contracts signed in 2001 by the California Department of Water Resources ("DWR") offers any insights into the reasonableness of the proposed PPA?

A. No. Mr. Hieronymus goes to great lengths to use the contracts signed by the California DWR as a benchmark to show that the proposed PPA would be reasonable.[30] However, the contracts signed by the DWR during 2001 are a widely recognized disaster that have committed the State of California to pay extremely high prices for power. These flawed and significantly overpriced short-term and long-term contracts are being challenged by the California State Auditor, the California Public Utilities Commission ("PUC") and the Attorney General, among others.

For example, the California PUC recently filed a complaint at FERC against specified sellers of long-term power contracts to the California DWR. In this complaint, the CPUC addressed 32 contracts between the DWR and 22 sellers. The California PUC's preliminary calculations indicated that collectively the challenged contracts are priced at levels exceeding just and reasonable prices by approximately $21 billion.[31] The PUC further noted that the DWR was forced to procure enormous amounts of power in order to keep the lights on in California "under conditions of extreme market power."[32]

> In the months in which DWR negotiated the bulk of the contracts (February – April 2001), spot market prices averaged over $300/MWh every hour of every day-ten times higher than prior year prices. Suppliers took advantage of their market power and charged unreasonable prices, for unreasonably lengthy periods, and under unreasonable non-price terms and conditions. DWR was forced to accept these terms or let the state go black.

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30 For example, see the Testimony of APS witness Hieronymus, at page 5, line 7, to page 6, line 9.

31 California Public Utilities Commission Press Release, dated February 24, 2002.

32 Ibid.

A December 2001 Report by the California State Auditor similarly has noted that the decision to enter into about 40 agreements with a value of $35.9 billion in just 30 days may have affected the composition and details of the contracts signed by the DWR:

> The speed in which the department entered into contracts in response to the crisis precluded the planning necessary for a power-purchasing program of this size. As a result, it assembled a portfolio of power contracts that presents significant risks that will need careful management to avoid increased costs to consumers. [33]

The State Auditor's report further noted that the majority of the contracts entered into by the California DWR were not written to ensure a reliable source of power, but instead conveyed **lucrative financial terms** upon the suppliers to ensure that energy is delivered.[34] In addition, the terms of the contracts contain provisions that can increase the cost of power; thus they need careful management to avoid additional costs to consumers.[35]

Even Mr. Hieronymus had to acknowledge in his testimony that there are serious problems with the DWR contracts. Contrary to what Mr. Hieronymus may claim, these critically flawed contracts, which the State of California is now seeking to renegotiate, do not show that the proposed PPA is reasonable. Instead, they show what can happen if energy providers and their regulators rush into long-term contracts especially where, as here, the commission would be surrendering its oversight authority by approving the long-term agreement.

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[33] *California Energy Markets, Pressures Have Eased, but Cost Risks Remain,* at page 1.

[34] *California Energy Markets, Pressures Have Eased, but Cost Risks Remain,* at page 2.

[35] *California Energy Markets, Pressures Have Eased, but Cost Risks Remain,* at page 2.

Q. Please comment on the claim by APS witness Landon that "because the proposed PPA is based predominantly on the capital costs of existing units, and because market prices likely will rise over time to reflect the costs of new generation, which are likely to escalate, the final years of the [PPA] are probably the most valuable to rate payers."[36]

A. Mr. Landon's claim is overly optimistic, to say the least. First, it is not clear that ratepayers ever will see the claimed benefits in the final years of the PPA because either APS or PWCC could terminate the contract in 2015, 2020, or 2025 merely by providing notice to the other party at least twelve months prior to the scheduled end of the Agreement.[37]

At the same time, it is quite possible that the operating performance of APS' older fossil-fired generating facilities will decline as they age and their fuel and/or non-fuel operating costs will increase. Consequently, the costs of power may be significantly higher under the PPA than APS and its witnesses may now be willing to acknowledge. In contrast, the average age of the merchant generating capacity that APS could obtain through a competitive bidding process would be much younger and would not yet have begun to experience the O&M cost increases and deteriorating performance associated with power plant aging.

Q. What is your recommendation?

A. The Commission should reject APS' claims and disapprove the proposed PPA between APS and PWCC.

Q. Does this complete your testimony?

A. Yes.

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36 Testimony of APS witness Landon, at page 9, lines 17-20.

37 Purchase Power Agreement, Section 11.2(B), at page 22.

EXHIBIT DAS-1

David A Schlissel

Senior Consultant
Synapse Energy Economics
22 Crescent Street, Cambridge, MA 02138
(617) 661-3248 • fax: 661-0599

SUMMARY

I have worked for twenty-seven years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University and a law degree from Stanford Law School

PROFESSIONAL EXPERIENCE

Electric Industry Restructuring and Deregulation - Investigated whether generators have been intentionally withholding capacity in order to manipulate prices in the new spot wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales and auctions of power purchase agreements. Analyzed stranded utility costs in Massachusetts and Connecticut. Examined the reasonableness of utility standard offer rates and transition charges.

System Operations and Reliability Analysis - Investigated the causes of distribution system outages and inadequate service reliability. Evaluated the impact of a proposed merger on the reliability of the electric service provided to the ratepayers of the merging companies. Assessed whether new transmission and generation additions were needed to ensure adequate levels of system reliability. Scrutinized utility system reliability expenditures. Reviewed natural gas and telephone utility repair and replacement programs and policies.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Reviewed power plant operating, maintenance, and capital costs. Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors. Evaluated the reasonableness of contract provisions and terms in proposed power supply agreements.

Nuclear Power - Examined the impact of industry restructuring and nuclear power plant life extensions on decommissioning costs and collections policies. Evaluated utility decommissioning cost estimates. Assessed the potential impact of electric industry deregulation on nuclear power plant safety. Reviewed nuclear waste storage and disposal costs. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Economic Analysis - Analyzed the costs and benefits of energy supply options. Examined the economic and system reliability consequences of the early retirement of major electric generating facilities. Quantified replacement power costs and the increased capital and operating costs due to identified instances of mismanagement.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than seventy proceedings before regulatory boards and commissions in twenty one states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales.

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due tot he fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, March 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - July 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - June 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - December 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and May 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) - January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

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The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - February 1983 and February 1984
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U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

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Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2000 - Present: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society
- National Association of Corrosion Engineers
- National Academy of Forensic Engineers (Correspondent Affiliate)

BEFORE THE
ARIZONA CORPORATION COMMISSION

Direct Testimony of

NEIL H. TALBOT

Docket No. E-01345A-01-0822

On behalf of

The Arizona Corporation Commission Staff

March 29, 2002

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Table of Contents

DIRECT TESTIMONY OF NEIL H. TALBOT

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Neil H. Talbot and my business address is 22 Pearl Street, Cambridge, Massachusetts 02139.

Q. WHAT IS YOUR EMPLOYMENT?

A. I am an economic and financial consultant with Synapse Energy Economics, Inc.

Q. WHAT IS YOUR AREA OF EXPERTISE?

A. My area of expertise is electric utility economics.

Q. WHAT ARE YOUR ACADEMIC QUALIFICATIONS?

A. I obtained degrees in economics and finance from Cambridge University, England, and Boston College respectively.

Q. PLEASE OUTLINE YOUR EMPLOYMENT HISTORY.

A. Since 1968, I have been employed as an economic consultant, and during most of this period I have focused on the U.S. electric utility industry and, to a lesser extent, other public utility and energy industries. I have been associated with several consulting firms during this period -- first the Economist Intelligence Unit, London, then Arthur D. Little, Inc. of

Cambridge, Mass., and later the Tellus Institute of Boston and LaCapra Associates of Boston. Currently, I am employed as a consultant to Synapse Energy Economics, Inc., of Cambridge, Mass.

Q. PLEASE DESCRIBE YOUR CONSULTING WORK.

A. Since 1973, when I was retained by Potomac Electric Power Company of Washington, D.C., to do a long-term load forecast, I have spent most of my time working on the U.S. electricity industry. Since the early 1990s, most of my work has focused on industry restructuring. My professional biography is attached as Exhibit NHT-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THESE PROCEEDINGS?

A. I am a member of the Synapse Energy Economics team that has been retained by the Utilities Division ("Staff") of the Arizona Corporation Commission to review the variance request of Arizona Public Service Company ("APS" or "the Company") and related electric restructuring issues.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will address the electric restructuring experience of other states around the country. On the Synapse team, my focus has been to provide Staff with a survey of selected states. The survey is included in the

Staff Report in the Generic Electric Restructuring Docket, E-00000A-02-0051, dated March 22, 2002, as Appendix One. In this testimony I will attempt to draw general conclusions from the experience of these other states, and apply it to the present situation faced by the Commission as a result of APS's variance request.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. After this introductory section, I present a summary of my testimony, a discussion of recent trends in the electric industry, and a description of the conditions that I believe are necessary to support a workably competitive electric industry.

II. Summary

Q. IS IT POSSIBLE TO MAKE AN ASSESSMENT OF RESTRUCTURING AT THIS POINT IN TIME?

A. I think it is far too early to be able to make a balanced assessment of electric restructuring. The federal authorities are only gradually getting to grips with the problems of ensuring that the interstate wholesale markets function competitively. Even the states that are furthest along with retail restructuring are still in the transitional phase. One reason is that, in many of the states, the first years of restructuring have been overshadowed by stranded cost recovery, the hangover of the excess generation cost problem of the 1970s and 1980s. The bulk of stranded cost recovery is being phased out during the next several years, which will still be transitional years. Another reason is that regulators and customers are still leaning heavily on utility standard offer service. While this may be a necessary safety net for customers, it slows down the development of the competitive marketplace. Retail markets will face new challenges if and when standard offer service is terminated.

Q. HOW HAS THE CALIFORNIA CRISIS AFFECTED STATES' RESTRUCTURING EFFORTS?

A. The California crisis, along with wholesale power market problems in other regions, has brought about a fundamental reassessment. For states that had not yet restructured, I believe the balance of considerations has changed. In 1999, restructuring seemed to be a matter of urgency, and it was widely believed that states that did not get on the bandwagon would lose competitive advantage. Now it appears that there are real risks to restructuring precipitately, before market conditions are ready.

Q. HOW WOULD YOU SUMMARIZE THE NEW BALANCE OF CONSIDERATIONS?

A. For many states such as Arizona, the immediate decision is whether to proceed with restructuring or to delay. What are the benefits and costs of proceeding? On the benefits side, it is fair to say that as far as electricity customers are concerned, the near-term benefits of direct access have generally been disappointing. It is true that customers have benefited from utility rate reductions and rate freezes that have been part of the overall package in many states. But lower utility rates are not an essential part of restructuring as such. What is more relevant is the record of market prices to date, and this has been mixed. There may be an exception in the case of some large business customers, who have successfully entered into bilateral contracts with competitive providers. On the cost side, it is now clear that there are risks that had not been anticipated. These risks include the danger of market power and increased electricity prices, risks associated with the loss of state regulatory jurisdiction, and even risks of electricity market failure.

Q. AFTER THE SETBACKS OF THE PAST TWO YEARS, IS ELECTRIC RESTRUCTURING CONTINUING OR IS IT STALLING OUT?

A. Electric restructuring is certainly slowing down or being delayed in most of the states that were planning to restructure in the near future or were currently starting to restructure. And states that had not yet started planning for restructuring by 2000 are now more likely to adopt a wait-and-see approach. On the other hand, in those states that had already restructured by 2000, I do not see a strong desire to re-regulate. In any case, in those states the genie is out of the bottle -- it would be very difficult for them to return to traditional regulated utility operations, because they no longer have jurisdiction over generation assets. Rather, the primary question those states are asking is how they can make competition more effective.

Q. WHY DO YOU THINK TEXAS DECIDED TO OPEN UP ITS RETAIL MARKET ON SCHEDULE ON JANUARY 1, 2002?

A. The main reason is that the Texas authorities are convinced that they can avoid the downside risks of restructuring. They went through a checklist of California problems and reached the conclusion that they did not apply to Texas. I think there is another factor. How states are responding to this changing situation depends as much on their views regarding markets versus regulation, as on the evidence provided by the experience to date. In looking at emerging competitive markets, state authorities seem to be able to see the glass as either half empty or half full. Texans see it as half full.

Q. WHAT ROLE ARE THE FEDERAL AUTHORITIES PLAYING?

A. I don't know what legislation might emerge from Congress. What is clear, however, is that the Federal Energy Regulatory Commission (FERC), under its new chairman, Patrick H. Wood III, who was formerly the head of the Texas commission, is totally committed to opening up interstate transmission systems to new power producers and to retail customers. I believe FERC will achieve this broad goal in the next several years. This will or should make it possible for states to place greater reliance on the wholesale market than would now seem prudent.

Q. ASSUMING FERC SUCCEEDS IN ACHIEVING ITS BROAD GOAL, DOES THIS MAKE IT MORE LIKELY THAT STATES WILL CONTINUE WITH THE TRANSITION?

A. My view is that, yes, the more likely scenario is that most states will continue with the transition toward retail competition, in a wholesale market framework created by FERC-approved Regional Transmission Organizations (RTOs). But it will depend on states having confidence that the right conditions are in place in the state retail market as well as the regional wholesale market.

Q. IT SEEMS THAT THERE IS CONSIDERABLE UNCERTAINTY. IS IT POSSIBLE THAT SOME STATES WILL HOLD OUT?

A. Yes. It seems quite possible that some states will simply say no. In New England, five of the six states have restructured their utilities and adopted direct retail access, but Vermont has said no. In the sample of states the

Synapse team has surveyed for the Commission Staff, Maine is happy that it has restructured, and Vermont is happy that it hasn't. Vermont may stay that way indefinitely.

Q. IN THAT SCENARIO, SOME STATES RESTRUCTURE, OTHERS DON'T. ARE THERE OTHER POSSIBLE SCENARIOS?

A. It seems possible that there will be some other crises, and/or the competitive market will underperform people's expectations and will be written off as a failure. In which case presumably the number of holdout states will be greater, and some states that have adopted direct access may start moving back in the direction of increased regulation.

Q. ARE THERE COMPROMISE SOLUTIONS?

A. Yes. Even if most people still think the competitive market is a success, another scenario seems quite possible. Some states may end up with a hybrid type situation, *e.g.*, large industries or groups of customers may shop around for electricity in the generation market, while residential and small business customers stay with regulated standard offer service indefinitely.

Q. WHAT IS YOUR RECOMMENDATION TO THE ARIZONA COMMISSION AT THIS TIME?

A. My foremost recommendation is that the risks of restructuring should be carefully weighed against the potential benefits before APS is allowed to take any irrevocable steps in the direction of restructuring.

Q. ASSUMING THE COMMISSION DECIDES TO DELAY RESTRUCTURING, WHEN SHOULD IT REVIEW THAT DECISION?

A. I would suggest that the Commission delay its decision pending the outcome of its investigations in the generic restructuring docket. I further suggest that the Commission continue to review the experience of restructuring in other states and regions across the country. I would not recommend that Arizona proceed with restructuring unless and until the Commission ensures that a smoothly functioning, well-designed, competitive wholesale electricity market is in place in Arizona and the region. Unless and until this finding is made, the risks of restructuring are not worth taking.

Q. SHOULD THE COMMISSION APPROVE THE TRANSFER OF APS GENERATION ASSETS TO AN AFFILIATE AT THIS TIME?

A. No. I recommend that the Commission not approve such a step at the present time. I believe that the transfer would result in a loss of Commission jurisdiction over APS's generation assets. I believe that delay -- or some alternative plan that retains state jurisdiction for the time being -- would be preferable to premature restructuring. Subject to legal considerations, the Commission may wish to consider an alternative along the lines being considered by the Virginia State Corporation Commission for two utilities. This is the functional separation of APS's generation assets within a separate division of APS, *i.e.*, retaining the generation assets in APS as a corporate entity.

III. Recent Trends in the Electric Industry

Q. PLEASE OUTLINE THE INDUSTRY TRENDS THAT YOU BELIEVE ARE RELEVANT TO THE CURRENT RESTRUCTURING SITUATION.

A. Up until the oil crisis of 1973-1974, the electric utility industry was a growth industry that doubled in size every decade, as the use of electric appliances spread. The industry enjoyed declining costs in a framework of well-structured state and federal regulation. Signaling the end of its high-growth phase, the industry's costs started to increase in the late 1960s, and some electric end-uses began to reach high levels of saturation.[1] Instead of

[1] The National Power Survey, 1970, issued by the Federal Power Commission (predecessor of the Federal Energy Regulatory Commission) in early 1973, a year before the first oil crisis, presaged the changes in the industry. It documented how costs were starting to rise, and it contained an end-use forecast that showed how demand growth was dependent on appliance saturation levels.

the industry maturing gradually as might have been expected, however, the oil crisis of 1973-1974, and the slow-down of the economy, brought the industry's high-growth period to an abrupt end. The industry, hoping for a rebound, still planned to double its capacity in the 1970s. And wanting to reduce its dependence on oil and natural gas, it built larger and hopefully cheaper generators fueled by coal and nuclear fuel. However, slower growth in demand and the escalation of nuclear power plant costs, resulted in a build-up of costly excess capacity.

Q. WHO PAID FOR THAT EXCESS CAPACITY?

A. Under the continuing regulatory regime, customers bore most of the financial risk of excess capacity in the 1980s and 1990s. That is the principal reason why, in the 1990s, regulators in high-cost states looked for a new approach, which they found in restructuring the electric industry by breaking up vertically integrated utilities and deregulating generation. Meanwhile, natural gas, which had been deregulated and was now seen as abundant, could provide an economical fuel for a new generation of power plants.

Q. IS THERE AN ECONOMIC RATIONALE FOR RESTRUCTURING?

A. Yes. Most economists believe that the generation of electricity, and perhaps some other electricity services such as billing and metering, would be better provided in a competitive, deregulated market. This belief depends on the finding that these services are not "natural monopolies," *i.e.*, they are not subject to such strong economies of scale or scope that it is better for one company to provide them in each area on a non-competitive basis under state regulation. If their finding is correct, competition will bring benefits of lower prices, innovation, and customer choice. Economists assumed that these benefits would come without significant downside risks.

Q. WHAT HAVE BEEN THE BENEFITS AND RISKS OF THE RESTRUCTURING EFFORT SO FAR?

A. About one half of the states embarked on the restructuring process, or were planning to do so, by 1999. Some participants saw near-term benefits, others weren't so sure. I think it is fair to say that the near-term benefits of restructuring were somewhat disappointing, even to its proponents. Then, in 2000 and 2001, deregulated wholesale prices rose in the Midwest and to a lesser extent in certain other regions. And a "perfect storm" hit California -- a shortage of power, manipulation of the wholesale market by suppliers, distortions introduced by a complex and faulty market structure, and the bankruptcy or near-bankruptcy of the state's utilities. Unfortunately, it proved impossible to insulate other states in the West from being drawn into the wholesale market crisis. It seems that California's regulators, trying to devise a new structure that would shift the risk of excess costs from consumers to suppliers, had failed to keep their eye on the ball, and had subjected consumers in California and other states in the region to new risks. They had lost sight of the principal benefits that had been taken for granted under the regulatory system -- reliability and stability. Admittedly, regulated utility rates had been high in recent years, but the utilities had kept the lights on. Now, there was a risk of price volatility, extreme price spikes, and even blackouts.

Q. HAS THE COLLAPSE OF ENRON AFFECTED THE SITUATION?

A. No, not much, at least in the near term. Regulators already knew that competitive suppliers like Enron might fail. The Enron failure simply underscored the importance of trying to ensure that competitive suppliers are financially secure, and, when a failure occurs -- something that is bound to happen occasionally -- ensuring that default service is available to affected customers on reasonable terms.

Q. COULD THE COLLAPSE OF ENRON HAVE AN EFFECT IN THE LONGER TERM?

A. Yes. While the Enron affair is fundamentally about financial transparency and accounting practices, Enron's association with emerging deregulated energy markets has made those markets appear risky. The danger is that investors may shy away from the merchant power business if they associate it with excessive risk. Already, power plant construction plans are being cut back in response to falling electricity prices. The collapse of Enron could have the effect of increasing the cost of capital for merchant power ventures and energy marketers, and possibly reducing the availability of generation in the future.

Q. IN THE SYNAPSE SURVEY, WHAT DIFFERENT STATE APPROACHES DID YOU FIND?

A. Our survey was intended to document the responses of different states across the country to the developments to date. We selected fourteen states – some of which we discussed in detail, others in a more summary or focused fashion. The states were selected to show a variety of responses, and to attempt to explain why the responses have differed. The states fall into several groups. One group consists of states that had already established workably competitive wholesale markets with direct access by large business customers and even some residential and small business customers. It is not surprising that most of them have decided to stay the course. In our survey, Illinois, Maine, Ohio and Pennsylvania are in this group.

Q. WHAT HAS THE RESPONSE BEEN AMONG THOSE STATES THAT HAD NOT YET STARTED TO RESTRUCTURE?

A. Those states that had not yet embarked on restructuring, including Florida in our sample, seem to prefer to wait and see. Vermont, which had come close to passing restructuring legislation, made the same decision. Then there are states that have gone some distance toward restructuring -- they had passed restructuring legislation and were already in the process of restructuring, but had not yet reached the point of no return.

Q. THESE STATES ARE OF PARTICULAR INTEREST FOR ARIZONA. WHAT HAVE THEY DONE?

A. One state, Texas, has remained totally committed to restructuring, and has opened up its retail market to competition on schedule on January 1, 2002. The Texas authorities believe that the experience of the first months of retail access is bearing out their optimism. Few if any other states that are on the brink of restructuring have remained quite as sanguine as Texas about the prospects of restructuring. In our sample, Montana, New Mexico and Oregon have all delayed the process in one way or another, and retained the protection of utility regulation for an extended period. Two states – California itself and its neighbor Nevada – have effectively abandoned restructuring, and one, Arkansas, which had already decided on a two-year delay, is considering a more extended delay.

Q. PLEASE GO THROUGH THESE STATES AND TRY AND EXPLAIN *WHY* THEY DID WHAT THEY DID. WHY DID TEXAS DECIDE TO PROCEED UNDAUNTED?

A. In contrast to California, which encountered a perfect storm, the Texas PUC believes Texas is the state most likely to enjoy plain sailing. There are several factors that account for this optimism. First, the Texas commission has jurisdiction over its principal transmission operator, the ERCOT ISO, because most of the state has an intra-state grid. Without divided jurisdiction, it is easier for the state to have a consistent set of restructuring policies, and it does not have to pass a jurisdictional point of no return when utilities restructure. (Interestingly, direct access has been delayed in those parts of Texas in which utilities are interconnected to other regions.) Second, a related advantage is that Texas's ERCOT utilities cannot be side-swiped by crises in neighboring states. Third, the Texas legislation dealt up-front with the issue of market power. Utilities are required to auction off 15% of their generation, and no one entity may control more than 20% of the generation market. Fourth, it is relatively easy for merchant generators to get siting permission and to connect to the transmission grid -- unlike their fellow generators in some other states, they do not have to pay for the transmission connection and the rules for interconnection are not onerous. Fifth, conditions for direct access and customer aggregation appear to be conducive to competition -- a number of customers have already switched to competitive providers. Although most utility rates -- called "the price to beat" -- have been reduced, they still seem to be high enough to give alternative providers an opportunity to make attractive offers to customers. Having said all this, I believe another factor is the predisposition of the commissioners, including former chairman Pat Wood, now FERC chairman, to favor market solutions over regulatory ones. (This contrasts perhaps with the situation in states like Nebraska and Vermont, where I suspect the opposite view predominates.)

Q. PLEASE TURN TO THREE STATES IN YOUR SAMPLE THAT DECIDED TO DELAY RESTRUCTURING -- MONTANA, NEW MEXICO AND OREGON.

A. All these states were deeply affected by the California crisis. They wanted to protect retail customers from the wholesale prices that spread across the region. And they were concerned that it would take some time before the Western RTO situation would be resolved.

Q. PLEASE OUTLINE THE SITUATION IN MONTANA.

A. The Montana legislature and commission have delayed restructuring in two ways. First, in December 2000 the July 2002 deadline for retail access was delayed by the commission for two years to July 2004. Then the legislature stepped in and extended the transition period to July 2007.

Q. WHAT WAS THE OTHER WAY IN WHICH RESTRUCTURING WAS DELAYED IN MONTANA?

A. In December 1999, Montana Power Company (MPC), the state's principal investor-owned utility, had sold its generation assets to PPL Montana, which could get high prices for its output on the wholesale market in 2000/2001. MPC's access to low-cost power was at risk. In spring 2001, a five-year deal was negotiated at a price of 4 cents/kWh, a price that did not seem so unreasonable at the time, but seemed too high to the commission and others. Fortunately, the commission was able to cancel the deal. More important, the commission sought to establish jurisdiction over MPC's generation assets that had been sold to PPL Montana. It succeeded in doing this, by making the legal argument that under Montana law the sale was subject to MPC's obligation to provide standard offer service at cost-based regulated rates. In other words, the assets were still part of MPC's rate base, even though they had been sold. The legal situation, which appears to be different in Montana than other states, has kept lower-priced, cost-based, generation available for Montana's customers.

Q. WHAT IS THE SITUATION IN NEW MEXICO?

A. As was the case in Montana, the key issue was the transfer of utility generation assets. As the commission said, "Asset separation is the most significant act of restructuring and represents a point of no return for states moving toward deregulation." The transfer was scheduled to take place in August 2001, and retail access was to commence in January 2002. In the second half of 2000, as the California crisis unfolded, a number of stakeholders began pressing for delay in implementing retail competition. In March 2001, the legislature passed and the governor signed into law SB 266, which delayed the asset transfer to 2005 and direct access to 2007.

Q. WHAT IS THE SITUATION IN OREGON?

A. Again, the state legislature, in response to the instability of the Western wholesale market, decided to delay direct access for business customers from October 2001 to March 2002. Residential customers would no longer be given the choice of direct access, but they would be able to choose from among different options offered by their distribution utilities, including regular cost-based rates and green power.

Q. IN THESE STATES, THE RESPONSE TO THE WHOLESALE MARKET SITUATION WAS TO DELAY RESTRUCTURING, AND PROVIDE CUSTOMERS WITH THE PROTECTION OF COST-BASED RATES FOR AT LEAST SOME FURTHER PERIOD OF TIME. WHAT DID THE ARKANSAS AUTHORITIES DO?

A. Arkansas did basically the same thing. In November 2000, the commission reported to the legislature that the wholesale market was not yet ready for effective competition, and that market prices might be higher than regulated prices. This meant that the commission could not find that there would be public benefits from restructuring. The legislature delayed the date for initiating retail competition to October 2003, and gave the commission the discretion to delay it further, for two one-year periods. More recently, in a December 2001 report to the legislature, the commission took a bleak view of restructuring. It recommended either outright repeal of the statute or complete suspension "for a considerable period of time, perhaps going out to 2010 or 2012." Though not on the Western grid, and therefore not directly affected by the California crisis, Arkansas has some similar concerns to those expressed in Montana and New Mexico. Not only could market prices be higher than cost-based regulated prices, but there are market power concerns and the recognition that it will take some time to get an effective RTO in place.

Q. HAS NEVADA REPEALED ITS RESTRUCTURING ACT?

A. Yes. In April 2001, AB 369 repealed all previous restructuring legislation, and prohibited the sale of any generation assets by the incumbent utilities before July 2003. This was partly a response to the California crisis, and partly a reflection of local issues. Large customers, however, may shop for power, with commission approval and with certain conditions attached.

Q. WHAT LESSONS CAN BE LEARNED FROM THE EXPERIENCE OF THE STATES THAT WERE ON THE VERGE OF RESTRUCTURING IN 2000/2001?

A. States that were in the process of restructuring have re-assessed their plans in light of the California crisis, price increases and spikes in other wholesale markets, and the difficulty of achieving competition in retail markets. The outcome of these re-assessments has been determined by conditions in each state and wholesale market conditions in the region. State commissions and legislatures have been going through a checklist of California problems, and asking themselves if their state is vulnerable to the same problems. Texas believes it is not, and has gone ahead; Nevada believes it is, and has effectively abandoned the effort, at least for the time being.

Q. WHAT LESSONS DO YOU BELIEVE CAN BE LEARNED FROM THOSE STATES THAT HAD ALREADY RESTRUCTURED EARLIER?

A. Broadly, the near-term benefits of restructuring as such have not been significant. They have come mostly from rate reductions and price freezes that have been legislated or negotiated as part of the transition. Having said that, however, these states are mostly trying to deal with the problems and increase the benefits by taking steps to make the market *more* competitive, not by returning to rate regulation.

Q. HAVE CUSTOMERS SUCCESSFULLY SWITCHED TO COMPETITIVE SUPPLIERS IN THESE STATES?

A. The record so far is uneven. In four states in our sample in which restructuring has been in place for some time -- Illinois, Maine, Ohio and Pennsylvania -- it is proving difficult to get retail competition established in the residential and small business market. There is considerable variation between different parts of each state, e.g., in Ohio, the northern Ohio service territories of Cleveland Electric Illuminating Company and Toledo Edison account for almost all the switching in the state. These utilities' high prices provide the motive, and the formation of large governmental aggregators provides the means. In Ohio, governmental aggregation is made relatively easy because it can be of the opt-out variety – customers in a municipal area are included unless they choose to opt out. In Illinois, the Chicago area served by Commonwealth Edison Company (ComEd) accounts for most of the state's switching. Again, the motive is provided by ComEd's high rates. In Illinois, however, aggregation has not been a factor. Rather, it seems that the sheer concentration of customers in Chicago makes it feasible for marketers to sign them up without incurring excessive acquisition costs. In Maine, the legislation provides an alternative, indirect, means of bringing competition to small retail customers. Standard offer service is not part of the distribution utility's scope, it is put out to bid and awarded to competitive providers. Maine regards this approach as successful. In Pennsylvania, the "poster child" of retail restructuring, the development of the small retail market is also very uneven. Pennsylvania's reputation was based on the adequacy of its "shopping credits" – the credit given by utilities to customers who no longer took utility generation service. A relatively low "exit fee" for utility stranded costs, and the inclusion in the shopping credit of a retail adder to reflect alternative providers' retail overhead and marketing costs, are among the methods for increasing shopping credits. However, Pennsylvania's approach has not proved to be much more successful than the approaches of other states in the face of market price increases. Fully 30% of the customers who had switched to the competitive market in Pennsylvania have returned to utility standard offer service in the past year or so.

Q. HOW WELL HAVE THE WHOLESALE MARKETS FUNCTIONED IN THESE FOUR STATES?

A. Maine and Pennsylvania benefited (relatively speaking) from the existence of established "tight" power pools, NEPOOL and PJM respectively, that could evolve into ISOs and now RTOs by negotiation among stakeholders under the aegis of FERC. Some participants believe these regional entities are far from perfect, and there have been complaints of barriers to entry by new generators, and market manipulations that have increased prices. Nevertheless, these are functioning RTOs, and that is a big step forward.

Q. WHAT IS THE RTO SITUATION IN ILLINOIS AND OHIO?

A. The Midwest RTO is still getting off the ground. Meanwhile, there is a greater risk of supply shortfalls or transmission bottlenecks than there is in regions with established RTOs.

IV. Conditions Necessary to Support a Workably Competitive Electric Industry

Q. STEPPING BACK, WHAT CONDITIONS ARE NECESSARY TO SUPPORT A WORKABLY COMPETITIVE RETAIL ELECTRICITY MARKET?

A. It is now clear that there must be a workably competitive *wholesale* electricity market before the retail electricity market can function well. It was the poor design of the wholesale market mechanisms, exacerbated by shortages and by market manipulation, that was the Achilles heel of the California restructuring effort.

Q. WHAT ARE THE COMPONENTS OF A WORKABLY COMPETITIVE WHOLESALE ELECTRICITY MARKET?

A. First, an effective, independent RTO, which is responsible, along with state governments in the region, for putting the following substantive components in place. Second, open non-discriminatory transmission access for generators. Third, there must be no one supplier of generation services large enough to be able to exert market power. Fourth, planning and pricing mechanisms to ensure coordinated system operations, system expansion, and reliability. These could include such features as an effective capacity market, capability responsibilities for suppliers, and a congestion management system to provide investment price signals.

Q. IS FERC READY AND ABLE TO DO WHAT NEEDS TO BE DONE?

A. I believe FERC knows what needs to be done. However, it will find it difficult to deal effectively with certain problems, and unless it does so regional wholesale markets will not function as well as they should.

Q. WHAT ARE THESE PROBLEMS?

A. One is the problem of market power. Traditionally, FERC addressed this issue in connection with mergers. Now, unless states break up incumbent utility generation portfolios before they are released into the deregulated wholesale market, FERC will have to deal with the market power of the utility affiliates or purchasers of utility generation assets. Over time, independent power producers may also acquire market power.

Q. WHAT IS THE OTHER PROBLEM FERC WILL HAVE TO ADDRESS?

A. The other difficult problem is the lack of coordinated regional planning. Economists, having reached the conclusion that wholesale electric generation markets could be competitive, assumed this problem would be taken care of by the market, *i.e.*, by unregulated independent power producers. However, in the real world in which power flows across a network of wires with limited capacity, states have been reminded of this problem by the California crisis. It has been brought home to state regulators that supply problems in one state can draw in surrounding states. More generally, it is being recognized that, to replace state utility planning, some central agency in each region needs to coordinate the expansion of the generation and transmission systems, if bottlenecks and supply shortfalls are to be avoided. That agency will be the regional transmission organization (RTO). FERC Chairman Pat Wood has said, "The RTO is a recognition that the power business must be planned and operated regionally...The RTO ought to be the respected body that initiates regional planning by saying, 'In this large area we need these four projects to be built.' Then it becomes the states' responsibility."[2] This is an extemely important statement, because it recognizes that a "deregulated" competitive market can only flourish in a regulated framework. But it is easier said than done.

Q. IN ADDITION TO A ROBUST WHOLESALE MARKET, WHAT CONDITIONS ARE REQUIRED TO MAKE THE *RETAIL* MARKET FUNCTION COMPETITIVELY?

A. One can generalize from the experience of Illinois, Maine, Ohio and Pennsylvania that I discussed earlier. At least during the transition period, most customers are likely to stay with standard offer service offered by their local utility. Shopping credits, net of stranded cost "exit fees," are generally insufficient to justify switching, or to justify competitive suppliers undertaking the marketing and other costs of entering the small-customer market. The situation may improve when stranded cost recovery is

[2] Interview in Business Week, March 4, 2002, p. 30B. The role that I think Chairman Wood has in mind for the states is to ease power plant licensing and

completed and there is no longer an "exit fee." The barriers to the small customer market can also be reduced or eliminated by making customer aggregation easy, including municipal aggregation of the opt-out type. An indirect method is to put standard offer service out to competitive bid.

Q. WHAT ROLE, IF ANY, WOULD AFFILIATES OF DISTRIBUTION AND TRANSMISSION UTILITIES HAVE IN A COMPETITIVE MARKET?

A. In a competitive *retail* market, utility affiliates, if allowed to compete for customers, should be governed by a code of conduct that ensures that they are not favored over other suppliers. In a competitive *wholesale* market, no one independent supplier should be large enough to have significant market power. In the Texas restructuring, no generator may control more than 20% of supply in any market. The suppliers must not only be independent of each other, but also independent of distribution and transmission utilities. Ideally, separate non-affiliate corporations should control generation, distribution and transmission. Second-best solutions include the transfer of transmission to an affiliate that would be controlled by the RTO, and transfer of generation to a separate division or affiliate with a code of conduct governing relations with the distribution utility.

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transmission system upgrading, in other words to eliminate barriers to system

Q. EARLIER, YOU POINTED OUT THE DANGERS OF GENERATION ASSET TRANSFER, WHICH CAN BE "THE POINT OF NO RETURN" IN RESTRUCTURING. HOW DO YOU RECONCILE THAT CONCERN WITH THE NEED FOR INDEPENDENT GENERATORS IN A COMPETITIVE MARKET?

A. During the transition period, if there are concerns that the market is not yet competitive or may malfunction owing to shortages, etc., transfer of assets risks loss of state jurisdiction, and/or a switch from cost-based rates to higher market-based prices. This is what Montana and Nevada took decisive steps to avoid. However, if and when the state commission finds that the wholesale market is well-structured and adequately competitive, and if the state wishes to proceed in the direction of restructuring, the situation changes. Then, some kind of separation of assets -- and breaking up of assets into packages, none of which is large enough to have market power -- is necessary to avoid giving an affiliate generator an advantage in the deregulated local or regional market.

Q. IN THIS PROCEEDING, APS IS PROPOSING TO TRANSFER ITS GENERATION ASSETS TO AN AFFILIATE, PWEC. HOW WOULD YOU ASSESS THIS STEP AT THE PRESENT TIME?

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expansion.

A. From a public interest standpoint, I believe that the transfer of APS generation assets to PWEC should only be considered after the Commission has made a finding that the components of competitive wholesale and retail markets are in place.

Q. IS SEPARATION OF APS GENERATION ASSETS POSSIBLE WITHOUT THE COMMISSION LOSING JURISDICTION OVER THEM?

A. An alternative might be to retain generation assets in a separate division within APS, governed by a code of conduct. This appears to be the approach that the Virginia commission is taking with Dominion Virginia Power and Appalachian Power. In a December 18, 2001 *Order on Functional Separation*, in Appalachian Power Company Case No. PUE010011, the State Corporation Commission approved a stipulation that included agreement on the following matters, among others: "On and after January 1, 2002, (the Company) will continue the current functional separation of its distribution, transmission and generation functions by division...There will be a further inquiry into the terms and conditions for the proposed transfer of generation assets to an affiliate, to be conducted during calendar year 2002. This inquiry will examine, among other things, conditions necessary for the maintenance of reliable electric service and the development of an effectively competitive market for generation services." (Order, at pages 5-6)

V. Conclusion

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS?

A. My conclusions and recommendations to the Commission are contained in Section 2: Summary, above.

Q. DOES THAT COMPLETE YOUR TESTIMONY?

A. Yes, thank you.

NEIL H. TALBOT

Economic & Financial Consultant

Education

M.S.F.	Finance, Boston College, 1992
M.A.	Economics, Cambridge University, England, 1968

Employment History

1995 -	Economic and financial consultant to Synapse Energy Economics
1980-1994	Tellus Institute, Boston, Mass. Member of Energy Group responsible for utility economic, financial and regulatory analyses.
1973-1979	Arthur D. Little, Inc., Cambridge, Mass. Member of Managerial Economics Section responsible for public utility economic and planning studies and energy economics.
1968-1973	The Economist Intelligence Unit Ltd., London, England. Project leader of Caribbean economic development studies; research and consulting on industrial and utility economics.

Summary of Relevant Experience

Neil Talbot is an economic and financial consultant to Synapse Energy Economics, Inc. He has masters degrees in economics and finance from Cambridge University and Boston College respectively. He has had 32 years' experience as a consultant focusing primarily on utility company economic, financial and regulatory issues with the Economist Intelligence Unit of London, Arthur D. Little, Inc. of Cambridge, Mass., Tellus Institute of Boston, Mass., and Synapse Energy Economics, Inc. He has prepared a wide range of studies and testimony on utility planning, rate of return, mergers and acquisitions, incentive rates, financial modeling of utilities under alternative rate scenarios, valuation of utility assets and evaluation of utility projects and contracts.

In recent years, Talbot has focused on the new issues facing the electric utility industry. He is currently a member of the Synapse Energy Economics team retained by the Utah Committee of Consumer Services to review the proposed reorganization of PacifiCorp. He has been a consultant to the Arkansas Public Service Commission on the restructuring of the electric utility industry; his most recent assignments have been to advise on the rate-making treatment of the proposed merger (now cancelled) between Entergy (parent of Arkansas Power & Light Co.) and FPL Corp., and to draft a market power rule and filing guidelines which were recently submitted to the commission. Articles written by Talbot include *The Right Path for Electricity Restructuring: 10 Guidelines for State Legislation* (The Electricity Journal, January/February 1999) and *A Stranded Cost Recovery Alternative* (Electricity Journal, May 1998).

Talbot was retained in 1999 by the Utah Committee of Consumer Services to review the financial aspects of the proposed acquisition of PacifiCorp by ScottishPower, and by the Maine Office of Public Advocate to review the proposed acquisition of CMP Group by Energy East. On behalf of the Attorney General of Washington State, he testified in 1996 on the financial impacts of the proposed merger of Puget Sound Power & Light Company and Washington Energy Company. His focus was on financial impacts of the merger and he developed and applied a corporate financial model to the utilities.

Talbot has testified frequently on cost of capital for regulated utilities. In 1995, he presented testimony on behalf of the Illinois Citizens Utility Board (CUB) on the cost of capital of Northern Illinois Gas Company. His testimony also opposed the company's proposed incentive regulation plan, which the company withdrew during the proceedings. Also for CUB, he testified on the cost of service and cost allocations of Commonwealth Edison Company.

In 2000, Talbot assembled a Synapse Energy Economics team for the Vermont Department of Taxes to prepare valuations of the Hydroelectric Generating Facilities on the Connecticut and Deerfield Rivers. In the 1990s, Talbot appraised various hydroelectric power plants for towns in Vermont. He evaluated purchased power contracts of Public Service Company of New Hampshire and Bangor Hydro Electric in 1994 and 1995 respectively.

In other rate work, Mr. Talbot has reviewed the incentive regulation plan (Alternative Rate Plan) for Central Maine Power Company and the Alternative Marketing Plan of Bangor Hydro, in testimony before the Maine Public Utilities Commission. He is the author of an AARP position paper entitled *Evaluating Price Cap Proposals in the Electric Utility Industry*. In 1998 he completed a *Sunset Review of the Energy Center of Wisconsin*.

Selected Testimony

Agency	Case or Docket No.	Date	Topic
Maine Public Utilities Commission	99-411	Sept. 1999	Acquisition of Central Maine Power by Energy East
Utah Public Service Commission	98-2035-004	June 1999	Acquisition of PacifiCorp (UP&L) by Scottish Power
Arkansas Public Service Commission	97-451-U	May 1998	Testified as Staff Expert in Electric Industry Restructuring Proceeding
Arkansas Public Service Commission	96-360-U	July 1997	Changes in Retail Rates and Transition to Competition Plan
Washington U.T.C.	UE-960195	Sept. 1996	Proposed Merger of Puget Sound P&L and Washington Natural Gas Co.
Maine Public Utilities Commission	96-187	Aug. 1996	Proposed Interim Competitive Transition Charge Tariff of Central Maine Power Co.
Illinois Commerce Commission	95-219	Nov. 1995	Incentive Regulation and Rate of Return for Northern Illinois Gas Company
Maine Public Utilities Commission	95-901	April 1995	Evaluation of Purchased Power Contract Buyout Proposals of Bangor Hydro
California Public Utilities Commission	A.93-12-029	Sept. 1994	Performance Based Ratemaking for Southern California Edison Company
N. Hampshire Public Utilities Commission	93-179	June 1994	Eval. of proposed buyouts by Public Service Company of New Hampshire of long-term purchased power contracts

Illinois Commerce Commission	94-0065	June 1994	Division among customer classes of an increase (or decrease) in revenue requirements for Commonwealth Edison Company, focusing on cost-of-service studies, both marginal and embedded
Kansas Corporation Commission	176,716U	Oct. 1991	Fair rate of return for KPL's Kansas gas operations
Kansas Corporation Commission	172,745-U 174,155-U	Jan. 1991	Proposed merger of Kansas Gas & Electric Company and Kansas Power & Light Company
New Hampshire Public Utilities Commission	DF 89-085	July 1990	Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation
New Hampshire Public Util. Com.	DR-89-244	March 1990	Rate impact of Northeast Utilities take-over of Publ. Serv. Co. of N.H.
Pennsylvania Public Utility Commission	R-891364	Oct. 1989	Fair rate of return and financial impact of rate recommendations on Philadelphia Electric Company
West Virginia P. S. Com.	Case No. 89-173-E-GI	Aug. 1989	Annual fuel review of Appalachian Power Company
Connecticut D. P. U. C.	89-02-16	June 1989	Fair Rate of Return and Rate Design for Connecticut Water Company
New York Public Service Commission	29484 and 88-E-084	July 1988	10-Year Rate Plan of Long Island Lighting Company
Public Service Commission of Utah	87-035-27	Apr. 1988	Effects of the Proposed Merger on UP&L's Energy Balancing Account and on Its Financial Sit. and Cost of Capital
New Mexico Public Service Commission	1811	Jan. 1988	Fair Price for Coal Resources
Public Service	38045	Nov.	Evaluation of a power plant for Northern

Com. of Indiana		1986	Indiana Public Service Company
Public Service Commission of Maryland	8522	July 1986	Management Audit of Potomac Electric Power Company's Fuel Procurement Practices
West Virginia Public Service Commission	86-081-E-GI 86-082-E-GI	May 1986	Economic Analysis of Pumped Storage Facility
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224	June 1985	The Financial Impact of Alternative Rate Treatments of Wolf Creek on Kansas City Power & Light Company
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U	April 1985	Concerning Wolf Creek Fuel Procurement and Nuclear and Other Fuel Costs
State of Connecticut D. P. U. C.	84-02-09	June 1984	Fair Rate of Return for Connecticut Natural Gas Company
Public Service Commission of Utah	80-035-17	Jan. 1981	Long-range Forecast: Electric Energy Requirements and Peak Demand
Ohio Power Siting Commission		July 1978	CAPCO Power Pool Load Forecast
Idaho Public Utilities Commission		March 1976	Evaluation of Pioneer Power Plant

Consulting, Research & Papers

Ongoing — Member of Synapse Energy Economics team evaluating PacifiCorp reorganization proposals

1996-2001 — Consultant to the Arkansas Public Service Commission on electric utility industry restructuring and competitive retail access.

1996-2000 — Consultant to New Jersey Division of Ratepayer Advocate on electric utility industry restructuring and competition, working regularly in client's office as staff consultant drafting position papers

January 1999	*The Right Path for Electricity Restructuring: 10 Guidelines for State Legislation*, Electricity Journal, Vol.12, No. 1
May, 1998	*A Stranded Cost Recovery Alternative*, Electricity Journal, Vol.11, No. 4
October, 1996	*A Consumer's Skeptical Perspective on Multi-Year Price Cap Plans*, Presentation to Washington, D.C. Conference on *Performance-Based Ratemaking for Electric & Gas Utilities* (Int. Bus. Communications)
August, 1996	*Evaluating Price Cap Proposals in the Electric Utility Industry*, published by American Association of Retired Persons.
July, 1996	*Appraisal of New England Power Company's Moore Station*, a report for Town of Waterford, Vermont
February, 1996	Consultant of Pennsylania Office of Consumer Advocate on Multi-Year Rate Plan of Pennsylvania Power Company
1995	Consultant to City of Wynnewood, Oklahoma, on Long-Term Power Contract with Oklahoma Municipal Power Assoc.
December, 1995	Support for Great Bay Power Corp. with Regard to Cost of Equity Capital in its Cost-of-Service Filing with F. E. R. C.
February 1995	Comments on Retail Competition in the Electric Power Industry Filed with New Hampshire PUC on Behalf of the Office of the Consumer Advocate
December 1994	Assistance on public utility holding company and diversification proposal of Pennsylvania Power & Light Company
November 1994	Preparation of Comments on Electricity Competition filed with the Pennsylvania PUC by the Office of Consumer Advocate
1992-1993	Co-ordinator of Energy and Environmental Alternatives Planning Assistance Program - Africa. For Stockholm Environment Institute.
1993:	*Zambia: Resuming the Energy Transition*. A report to: Zambia Department of Energy. Co-author. For Stockholm Environment Institute, funded by Swedish International Development Agency.

1994:	*Zimbabwe: Energy End-Uses and End-Use Efficiency.* A report to: Zimbabwe Department of Energy. For Stockholm Environment Institute and Swedish International Development Agency. Co-author.
Oct. 1993	*Financial Economics and Renewable Energy,* presented at: NARUC-DOE National Conference on Renewable Energy, Savannah, Georgia, Oct. 3-6.
July 1992	*Integrated Energy - Environment Planning: Experiences from the United States and Africa,* paper presented with Michael Lazarus, at South African Energy Policy Research and Training Project Workshop, Cape Town.
December 1991	Appraisal of Harriman Hydroelectric Plant of New England Power Co. A report to Town of Whitingham, Vermont. Principal author. 89-047.
Jan.-June 1991	U.S. Agency for Int. Development. Senior Econ. for energy price reform studies for Romania. Provided advice to government regarding energy price reform, energy planning and environmental impacts.
July 1977	*Management Effectiveness and Operating Efficiency of Kansas Gas and Electric Company,* a report to the Kansas Corporation Commission. Co-author.
Feb. 1976	*Idaho Power Company's Need for Additional Generating Capacity,* a report to Idaho Public Utilities Commission. Principal investigator.
Apr. 1974	*Inflation and Economic Growth in the U.S. Virgin Islands,* a report to the Legislature of the U.S. Virgin Islands. Principal investigator.
Jan. 1974	*A Study of International Inflationary Trends, with Special Emphasis on Algeria,* a report to the Algerian Government. Co-author.
Sept. 1973	*Long Term Load Forecast,* a report to Potomac Electric Power Co. Author.
Oct. 1976	Speech on *Load Forecasting for Electric Utilities* published in Proceedings of Need for Power Conference, Columbus, Ohio.

Professional Societies

Member, American Economic Association
Member, Financial Management Association
Member, National Association of Business Economists